Image Project Order File Cover Page

XHVZE

This page identifies those items that were not scanned during the initial production scanning phase. They are available in the original file, may be scanned during a special rescan activity or are viewable by direct inspection of the file.

0 006 **Order File Identifier**

Organizing (done) ☐ Two-sided ☐ Rescan Needed

RESCAN

☐ Color Items:

☐ Greyscale Items:

☐ Poor Quality Originals:

☐ Other:

DIGITAL DATA

☐ Diskettes, No.

☐ Other, No/Type:

OVERSIZED (Scannable)

☐ Maps:

☐ Other Items Scannable by a Large Scanner

OVERSIZED (Non-Scannable)

☐ Logs of various kinds:

☐ Other::

NOTES:

BY: Maria Date: 4/29/10 /s/ MP

Project Proofing

BY: Maria Date: 4/29/10 /s/ MP

Scanning Preparation ______ x 30 = ______ + ______ = TOTAL PAGES 68
(Count does **not** include cover sheet)

BY: Maria Date: 4/29/10 /s/ MP

Production Scanning

Stage 1 Page Count from Scanned File: 69 (Count **does** include cover sheet)

Page Count Matches Number in Scanning Preparation: ✓ YES ______ NO

BY: Maria Date: 4/29/10 /s/ MP

Stage 1 If *NO* in stage 1, page(s) discrepancies were found: ______ YES ______ NO

BY: Maria ______ Date: /s/

Scanning is complete at this point unless rescanning is required.

ReScanned

BY: Maria ______ Date: /s/

Comments about this file: Quality Checked

INDEX OTHER ORDER NO. 6

1.	September 23, 1980	Exxon requests that regulation 20 AAAC 25.035 Blowout equipment be revised
2.	October 24, 1980	Exxon ltr re: Variance to 20 AAC 25.035(c)(2)
3.	November 14, 1980	Notice of hearing, affidavit of publication
4.	December 17, 1980	Transcript of Hearing
5.	December 15, 1980	Proposed changes to Alaska Administrative code Title 20, 20 AAC 25.035
6.	December 22, 1980	Shell re: ltr proposed amendment
7.	----------------------	copy of old regulation
8.	January 16, 1981	affidavit of notice of adoption of regulation and affidavit of oral hearing
9.	January 23, 1981	Attorney General's Office comments

OTHER ORDER #6 (no order issued)

COMM
COMM
COMM
RES ENG
1 ENG
2 ENG
3 ENG
4 ENG
1 GEOL
2 GEOL
3 GEOL
STAT TEC
STAT TEC
CONFER:

ORDER AMENDING REGULATIONS OF
ALASKA OIL AND GAS CONSERVATION COMMISSION

The attached one page of regulations, dealing with Blowout Prevention Equipment are hereby adopted and certified to be a correct copy of the regulations which the Alaska Oil and Gas Conservation Commission amends under authority vested by AS 31.05.030 and after compliance with the Administrative Procedure Act (AS 44.62), specifically including notice under AS 44.62.190 and 44.62.200 and opportunity for public comment under AS 44.62.210.

This action is not expected to require an increased appropriation.

This order takes effect on the 30th day after it has been filed by the lieutenant governor as provided in AS 44.62.180.

DATE: 1/16/81
Anchorage, Alaska

Hoyle H. Hamilton
Hoyle H. Hamilton
Chairman/Commissioner

Lonnie C. Smith
Lonnie C. Smith
Commissioner

Harry W. Kugler
Harry W. Kugler
Commissioner

I, Terry Miller, Lieutenant Governor for the State of Alaska, certify that on January 23, 1981, at 4:15 p.M., I filed the attached regulations according to the provisions of AS 44.62.040 -- 44.62.120.

Lieutenant Governor

RECEIVED
JAN 28 1981
Alaska Oil & Gas Cons. Commission
Anchorage

Effective February 22, 1981.)
Register 77, April 1981.)

The following parts of 20 AAC 25.035. BLOWOUT PREVENTION EQUIPMENT are amended to read as follows:

(c) Blowout Prevention Equipment:

(1) before drilling below the surface casing, and until completed, a well must have remotely controlled BOP's; the working pressure of the BOP's and associated equipment must exceed the maximum potential surface pressure, except that the annular preventer need not have a working pressure rating greater than 5000 psig; the BOP stack arrangements must be as follows:

(A) API 2M, 3M, and 5M stacks must have at least three preventers, including one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, one with blind rams, and one annular type;

(B) API 10M and 15M stacks must have at least four preventers, including two equipped with pipe rams with at least one fitting each size of drill pipe, tubing, or casing being used, one with blind rams and one annular type;

(2) information submitted with Form 10-401 must include the maximum downhole pressures which may be encountered, the maximum potential surface pressures, the criteria used to determine these pressures, and a well-control procedure which indicates how the preventers will be used for pressure control operations if the maximum surface pressures should exceed the rated working pressure of the annular preventer;

(5) the BOP equipment must include a drilling spool with side outlets (if not on the blowout preventer body), a minimum three-inch choke line and a minimum two-inch choke manifold, a kill line, and a fillup line; the drilling string must contain full opening valves above and immediately below the kelly during all circulating operations using the kelly, with the necessary valve wrenches conveniently located on the rig floor; and

(6) two emergency valves with rotary subs for all connections in use and the necessary wrenches must be conveniently located on the drilling floor; one valve must be an inside spring-loaded or flow activated type; the second valve must be a manually operated ball type, or equivalent valve. (Eff. 4/13/80, Reg. 74; am 2/22/81, Reg. 77)

Authority: AS 31.05.030

NOTE: Replaces portions of pages 7 and 8 of the Regulations.

9

MEMORANDUM

State of Alaska

TO: Hoyle H. Hamilton
Chairman
Alaska Oil and Gas
Conservation Commission

DATE: January 23, 1981

FILE NO: J-99-088-81

TELEPHONE NO: 465-3686

FROM: WILSON L. CONDON
ATTORNEY GENERAL

By:
Arthur H. Peterson
Assistant Attorney General
and Regulations Attorney

SUBJECT: Commission regulation on blowout prevention equipment (20 AAC 25.035(c)(1), (2), (5), and (6))

Under AS 44.62.060, we have received your amendments of 20 AAC 25.035(c)(1), (2), (5), and (6), and approve them for filing by the lieutenant governor. A duplicate original of this memorandum is being furnished the lieutenant governor, along with your amended regulation and related documents.

In accordance with AS 44.62.125(b)(6), some corrections have been made in this regulation, as shown on the attached copy.

Your adoption order states that this action is not expected to require an increased appropriation. Therefore, AS 44.62.195 does not require a fiscal note. In addition, since no increased appropriation will be required, it is the opinion of this department that your failure to comply with AS 44.62.200(a)(5) by summarizing the fiscal information in your public notice is of no significance.

AHP:bjl

cc w/enc.: Jeffrey Lowenfels
Assistant Attorney General
Anchorage

RECEIVED
JAN 28 1981
Alaska Oil & Gas Cons. Commission
Anchorage

COMM
COMM
COMM
RES ENG
1 ENG
2 ENG
3 ENG
4 ENG
1 GEOL
2 GEOL
3 GEOL
STAT TEC
STAT TEC
CONFER:
FILF:

The following parts of 20 AAC 25.035. BLOWOUT PREVENTION EQUIPMENT are amended to read as follows:

(c) Blowout Prevention Equipment:

(1) before drilling below the surface casing, and until completed, a well must have remotely controlled BOP's; the working pressure of the BOP's and associated equipment must exceed the maximum potential surface pressure, except that the annular preventer need not have a working pressure rating greater than 5000 psig; the BOP stack arrangements ~~shall~~ must be as follows:

(A) API 2M, 3M, and 5M stacks must have at least three preventers, including one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, one with blind rams, and one annular type;

(B) API 10M and 15M stacks must have at least four preventers, including two equipped with pipe rams with at least one fitting each size of drill pipe, tubing, or casing being used, one with blind rams and one annular type;

(2) information submitted with Form 10-401 must include the maximum downhole pressures which may be encountered, the maximum potential surface pressures, the criteria used to determine these pressures, and a well-control procedure which indicates how the preventers will be used ~~utilized~~ for pressure control operations if the maximum surface pressures should exceed the rated working pressure of the annular preventer;

(5) the BOP equipment must include a drilling spool with side outlets (if not on the blowout preventer body), a minimum three-inch choke line and a minimum two-inch choke manifold, a kill line, and a fillup line; the drilling string must contain full opening valves above and immediately below the kelly during all circulating operations using the kelly, with the necessary valve wrenches conveniently located on the rig floor; and

(6) two emergency valves with rotary subs for all connections in use and the necessary wrenches must be conveniently located on the drilling floor; one valve must be an inside spring-loaded or flow activated type; the second valve must be a manually operated ball type, or equivalent valve.

(Eff. 4/13/80, Reg. 74; am. / /81, Reg.)

Authority: AS 31.05.030

RECEIVED

JAN 28 1981

#8

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

AFFIDAVIT OF NOTICE OF ADOPTION OF REGULATION

I, Hoyle H. Hamilton, Chairman/Commissioner, of Alaska Oil and Gas Conservation Commission, being sworn, depose and state the following:

As required by AS 44.62.190, notice of the proposed amendment of Title 20, AAC 25.035 has been given by

(1) being published in a newspaper or trade publication,

(2) being mailed to interested persons,

(3) being mailed or delivered to appropriate state officials,

(4) being furnished to the Department of Law,

(5) being furnished to incumbent State of Alaska legislators and the Legislative Affairs Agency.

DATE: 1/16/81
Anchorage

Hoyle H. Hamilton
Hoyle H. Hamilton
Chairman/Commissioner

SUBSCRIBED AND SWORN TO before me this 16th day of January 1981.

Nola J. Bragg
Notary Public ~~in~~ and for Alaska
My commission expires: 5-9-81

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

AFFIDAVIT OF ORAL HEARING

I, Hoyle H. Hamilton, Chairman/Commissioner of the Alaska Oil and Gas Conservation Commission being sworn, depose and state the following:

On December 17, 1980 at 9:30 AM, in the Municipality of Anchorage Assembly Room in Anchorage, Alaska, I presided over the public hearing held in accordance with AS 44.62.210 for the purpose of taking testimony in connection with the amendment of Title 20, AAC 25.035.

DATE: 1/16/81
Anchorage

Hoyle H. Hamilton
Hoyle H. Hamilton,
Chairman/Commissioner

SUBSCRIBED AND SWORN TO before me this 16th day of January, 1981.

Nola J. Bragg
Notary Public in and for Alaska
My Commission expires: 5-9-81

7

will be changed via Cons. Order #... 2/17/80 hearing

OLD REGS

(89)

(c) Blowout Prevention Equipment:

(1) before drilling below the surface casing, a well must have a minimum of three remotely controlled BOP's, including one equipped with pipe rams that fit the size of drill pipe or casing being used, one with blind rams, and one annular type;

(2) the working pressure of any BOP and associated equipment must exceed the maximum surface pressure to which they may be subjected; information submitted with Form 10-401 must include the anticipated downhole pressures to be encountered, the maximum surface pressures to which the BOP equipment may be subjected, and the criteria used to determine these pressures;

(3) the hydraulic actuating system used must provide sufficient accumulator capacity to supply 1.5 times the volume of hydraulic fluid necessary to close all BOP equipment; the system must also be capable of maintaining a minimum remaining pressure of 200 psig above the required precharge pressure when all BOP's are closed with the primary power source shut off; an accumulator backup system, supplied by a secondary power source independent of the primary power source, must be provided with sufficient capacity to actuate all BOP equipment;

(4) in addition to the primary controls on the accumulator equipment unit, at least one operable remote BOP control station must be provided; this control station must be in a readily accessable location on or near the drilling floor; a device to avoid unintentional closure must be provided on all remote blind ram closing controls;

(5) the BOP equipment must include a drilling spool with minimum two-inch side outlets (if not on the blowout preventer body), a minimum three-inch choke line and minimum two-inch choke manifold, a kill line, and a fillup line; the drilling string must contain full opening valves above and immediately below the kelly during all circulating operations using the kelly, with the necessary valve wrenches conveniently located on the rig floor; and

(6) two emergency valves with rotary subs for all connections in use and the necessary wrenches must be conveniently located on the drilling floor; one valve must be an inside BOP of the spring-loaded type; the second valve must be of the manually operated ball type, or equivalent valve.

(d) Testing:

(1) all ram-type BOP's, kelly valves, emergency valves and choke manifolds must be tested to the rated working pressure or to the maximum surface pressure as required to be submitted in (c)(2) of this section; annular preventers must be tested to not less than 50 percent of the rated working pressure; these tests must be made when the BOP equipment is installed or changed and at least once each week thereafter; test results must be recorded as required by sec. 70(a)(1) of this chapter;

(2) to insure that minimum standards are achieved, the operator shall perform the recommended tests for BOP closing units specified in sections 5A and 5B of API RP 53; and

(3) sufficient notice of certain BOP equipment tests must be given so that a representative of the commission can witness these tests; these tests will be specified in the drilling permit or by notice to the operator.

(e) BOP equipment for cable tool drilling activities must have prior commission approval and must be in accordance with good established practice with all equipment in good operating condition at all times. (Eff. 4/13/80, Reg. 74)

Authority: AS 31.05.030

#6

Shell Oil Company
601 West Fifth Avenue • Suite 810
Anchorage, Alaska 99501

Cons. File #172

December 22, 1980

Mr. L.C. Smith, Commissioner
State of Alaska
Alaska Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, AK 99501

Dear Lonnie:

Thank you for sending us a copy of the proposed amendment of Title 20, AAC 25.035. I have reviewed this material and do have some comments that I would like to submit for your consideration.

Title 20 AAC 25.035 (c)(1)(A) and (B) contains wording that might be interpreted to mean that casing rams are required to be in place when casing is run. I agree in principle that casing rams provide an added safety factor. However, in order to install casing rams, it is necessary to open up the blowout preventer, thus breaking the body seal. After installing the casing rams, the preventer must be retested to ensure the integrity of the body seal and the rams. All of this work must be done while the drill pipe is out of the hole and preparations are being made to run casing. In most cases, hole conditions, from a well control standpoint, are such that this work can be accomplished with no significant risk.

However, there are those instances in which the control of a well can be jeopardized to a greater degree by taking the extra time to install and test casing rams and by breaking a preventer seal at a rather critical point in the operation. I would suggest, therefore, adding wording to Title 20 AAC 25.035 (c)(1) as follows:

> Casing rams should be used when running casing. It is recognized that in certain situations, the safety of the well may be jeopardized by changing rams preparatory to running casing. In those cases where it is decided casing rams should not be installed, a crossover from drill pipe to casing and drill pipe of sufficient strength to support the casing weight shall be on the rig floor ready for use.

RECEIVED
DEC 23 1980
Alaska Oil & Gas Cons. Commission
Anchorage

If you have any questions regarding the comments above, please do not hesitate to contact me.

Very truly yours,

M.L. Woodson
Production Superintendent
Alaska Operations

MLW:bb

#5

CO #72

Chevron

Chevron U.S.A. Inc.
575 Market Street, San Francisco, CA 94105
Mail Address: P.O. Box 7643, San Francisco, CA 94120

J. J. Anders
Manager, Alaska Division
Land - Western Region

December 15, 1980

PROPOSED CHANGES TO ALASKA
ADMINISTRATIVE CODE
TITLE 20, AAC 25.035

Mr. Harry W. Kugler
Commissioner
Alaska Oil & Gas Conservation Commission
3001 Porcupine Drive
Anchorage, Alaska 99501

Dear Mr. Kugler:

Chevron U.S.A. Inc. presents the following comments on the amendment of Title 20, AAC 25.035 of the Regulations as provided for in the Alaska Statutes, Title 31, Chapter 05, Article 1, Section 30.05.030 (c) and (d).

Title 20, AAC 25.035 (c) (1) (A) should be worded as follows:

API 2M, 3M and 5M stacks have at least three preventers including one with pipe rams which fit the drill pipe or tubing being used, (The rams in this preventer will be changed to fit the casing when casing is being run.) one with blind rams and one annular type.

Title 20, AAC 25.035 (c) (1) (B) should be worded as follows:

API 10M and 15M stacks have at least four preventers including two with pipe rams which fit the drill pipe or tubing being used, (One set of these rams will be changed to fit the casing when casing is being run.) one with blind rams and one annular type.

Title 20, AAC 25.035 (c) (6) should be worded as follows:

Two emergency valves with rotary subs for all connections in use and the necessary wrenches must be conveniently located on the drilling floor; one valve must be inside (BOP of the) spring loaded type (a flapper type float valve and float sub are considered to fill this requirement); the second valve must be of the manually operated ball type, or equivalent valve.

We do not have comments on the proposed changes to Title 20, AAC 25.035 (c) (2) and (c) (5).

We will be happy to answer any questions you may have on our comments.

Very truly yours,

J. J. Anders

RECEIVED
DEC 15 1980
Alaska Oil & Gas Cons. Commission
Anchorage

:JDB:sj

Public Hearing <u>12-17-80</u> Cons. File #172

Attending:

John Willis	Exxon	Harry Kugler Comm.
Richard Reiley	Sohio	Hoyle Hamilton Comm.
Blair Wondzell	AO&GCC	Lonnie Smith Comm.
Bill Van Alen	AO&GCC	Mike Arruda. A.G.

<u>Testimony</u> John B Willis :- Exxon - Agree if we mean 1 set of rams for each size pipe, tubing or casing being used!

<u>Testimony</u> Richard Reiley - Sohio
Two that fit the size of drill pipe, tubing or casing being run.

4:30 Dec. 31, 1980 - hearing closing date!

4

PUBLIC HEARING

STATE OF ALASKA
Alaska Oil and Gas Conservation Commission

Conservation File No. 172

In the Matter of
the Amendment of Title 20, AAC 25.035 of the Regulations as provided for in the Alaska Statues, Title 31, Chapter 05, Article 1, Section 31.05.030 (c).

DATE: December 17, 1980

PLACE: 3500 Tudor Road,
Assembly Meeting Room
Anchorage, Alaska

TIME: 9:40 a.m.

APPEARANCES:

HOYLE H. HAMILTON, Chairman of the Alaska Oil and Gas Conservation Commission

HARRY W. KUGLER, Commissioner with the Alaska Oil and Gas Conservation Commission

LONNIE C. SMITH, Commissioner with the Alaska Oil and Gas Conservation Commission

MICHAEL ARRUDA, with the Attorney General's Office, State of Alaska

AUDIENCE PARTICIPANTS:

JOHN B. WILLIS, Drilling Engineering Supervisor for Exxon Company U.S.A.

RICHARD H. REILEY, District Drilling Engineer for Sohio Alaska Petroleum Company in Anchorage

* * * * * * * *

P R O C E E D I N G S

MR. HAMILTON: Good morning. There's such a large group here, I suppose we ought to identify ourselves. I'm Hoyle Hamilton, Chairman of the Commission. To my left is Commissioner Harry Kugler. To my immediate right is Commissioner Lonnie Smith, and to my far right is Mike Arruda with the Attorney General's office.

This is a public hearing called by the Alaska Oil and Gas Conservation Commission to accept oral or written comments regarding the adoption of amended regulations as provided for in the Alaska Statutes, Title 31, Chapter 5, Article 1, Section 31.05.030 (c).

The proposed amendments are to Title 20 of the Alaska Administrative Code 25.035 (c) entitled Blowout prevention equipment. Notice of this hearing was published in the Anchorage Times on November the 14th, 1980. A copy of the published notice will be made part of the hearing record. Draft copies of the proposed regulation amendments are available here at the table if anyone cares to have a copy.

And the hearing record will be kept open for two weeks following today's hearing for any additional written comments. That will be until 4:30 p.m, December the 31st, 1980.

So at this time we would like to open it up for any public comments. We have two gentlemen in the audience. Which one would like to come forth first? And for the record, if you would, identify yourself and your affiliation before you give your comments.

MR. WILLIS: Okay. My name is John B. Willis, W-I-L-L-I-S. I'm drilling engineering supervisor for Exxon Company U.S.A.

COURT REPORTER: Would you mind being seated, please?

MR. WILLIS: Okay.

COURT REPORTER: Thank you.

MR. WILLIS: My technical qualifications are graduate of Texas A. & M. University 1974 with a B.S. degree in chemical engineering. I've been employed by Exxon for six and a half years, including five years drilling experience for which I've been in Alaska, supervising Exxon's drilling engineering group here in Anchorage, responsible for all of the technical planning and surveillance for North Slope exploration drilling program.

Exxon supports the proposed revision as written. I'd like to make one comment. We interpret Section (c) part (1) (B) to require no more than two sets of pipe rams under any conditions, specifically included for running casing. We interpret that to mean that one set of drill pipe and one set of casing ram will be sufficient, and that for a tapered string one set pipe rams for the large size drill pipe and one set for the small size drill pipe would be sufficient. As long as the Commission intended for the regulations to read -- have that meaning, then we fully support them.

Also following the hearing I'd like to submit our written request to the Commission on all of the supporting technical reasons for the change in the regulations to be entered as part of the hearing record.

MR. HAMILTON: Yes, they will be.

MR. WILLIS: Thank you.

MR. SMITH: Shall we ask questions now or what?

MR. HAMILTON: Yes, if you want to. John, would you come back, please?

MR. SMITH: If you don't mind, I have a question or two. With reference to your -- your interpretation of (c) (1) (B), you -- would you state that again? That -- that -- Do I understand that you interpret that to mean just no more than two set of pipe rams of the same size? Or two pipe rams in the stack?

MR. WILLIS: Two sets of pipe rams in the stack. The part I was referring to states, quote, "including two that fit the size of drill pipe or casing being used," unquote. That could possibly mean that we would have to have two sets of casing rams in the stack or two sets of pipe rams for each size of drill pipe being used, which would conflict the earlier requirement that we must have at least three pipe rams, three preventers --

excuse me, four preventers, including three sets with -- with rams in them.

So I wanted to make sure that we understood what the Commission meant on that, and if there's a con -- conflict we'd like to pursue that and possibly .....

MR. SMITH: No, that was -- that was not the intent.

MR. WILLIS: Okay.

MR. SMITH: It was as you stated. The wording of casing may or may not be appropriate here. It's because of the sizes of tubular goods .....

MR. WILLIS: Right.

MR. SMITH: ..... or tubing run on the North Slope .....

MR. WILLIS: Yeah.

MR. SMITH: ..... was specifically the way it got in there. We've already had suggestions about changing that from -- to just drill pipe or tubing.

MR. WILLIS: Uh-huh.

MR. SMITH: Or -- let me ask this question with regard to that. Do you normally -- does your company change the ra -- one set of rams when you're running casing? Now, I mean, not casing for tubing, but casing?

MR. WILLIS: Definitely.

MR. SMITH: You do?

MR. WILLIS: Yes. We require two sets of pipe rams while drilling, one below the drilling spool and one above the drilling spool. We have one set of blind rams below the spool. For running casing we replace the top set of pipe rams, which are above the spool, with casing rams (Indiscernible) have the blind rams below the spool to obtain well control at all times. And if we were to have some kind of a problem while we were running casing, we would nibble up additional blow-out preventers on top of this stack to get back our normal (ph) safety factor a couple preventer (ph). For tapered string we run one set of pipe rams for the small drill pipe and one set for the large drill pipe.

MR. SMITH: Do you think you would object if that was reworded to say that -- including two that fit either the size of drill pipe tubing or casing being used?

MR. WILLIS: No, that sounds very good.

MR. HAMILTON: Any more questions?

MR. KUGLER: Just a minute. We have a -- a written comment on this already here and it's from Chevron U.S.A., and their wording is similar to what Commissioner Smith was saying, that -- including two with pipe rams, which fit the drill pipe or tubing being used. Again we'd have to have the same understanding that you were talking about, that it means one for the drill pipe and one for the tubing, I guess.

MR. SMITH: Okay.

MR. KUGLER: Casing rams would always be changed to use the size casing, right?

MR. WILLIS: Right.

MR. SMITH: I have one more question. John, with regard to the previous submittal of data to support this hearing, did you ask to have that entered into the record?

MR. WILLIS: Yes.

MR. HAMILTON: Okay, it will be entered into the record. Thank you, Mr. Willis.

MR. WILLIS: Thank you.

MR. HAMILTON: Mr. Reiley.

MR. REILEY: Mr. Chairman and members of the State of Alaska Oil and Gas Conservation Commission, my name is Richard H. Reiley, R-E-I-L-E-Y. I'm the district drilling engineer for Sohio Alaska Petroleum Company in Anchorage. I graduated from the University of Alaska in 1969 with a Bachelor of Science degree in mining engineering. And in 1973 with a masters degree in engineering management. I have 10 years of drilling and production experience, including two years of drilling supervision for both exploration and developing wells in Alaska.

I'm currently responsible for the engineering planning and technical assistance for Sohio's exploration and development drilling activities in Alaska.

This testimony is in regards to Conservation File No. 172, the amendment of Title 20, AAC 25.035 of the Regulations as provided for in the Alaska Statutes, Title 31, Chapter 05, Article 1, Section 21.05.030 (c) and (d).

Sohio Alaska Petroleum Company supports the written testimony and conclusions of Exxon U.S.A. It supports the issuance of the Conservation File No. 172 as written, with the exception of Section (d) -- correction, Section (c), paragraph (B) should state, include, too, that fit either the size of the drill pipe -- pipe tubing or casing being used. Thank you.

MR. HAMILTON: Thank you, Mr. Reiley. Questions?

MR. SMITH: Not quite yet. Just a second. Let me regroup here a little bit on the review of this stuff a minute, Richard.

MR. REILEY: We might also state that our company policy is to use a set of casing rams whenever we're running intermediate or long string, as is Exxon.

MR. SMITH: Yes, Richard, have -- has your company previously operated a well with a BOP stack as per specifically these new regulations would allow, with a 5,000 annular on a 10,000?

MR. REILEY: Yes, sir. We are operating one now under an exception granted earlier this year on Challenge Island. The three ram stack, drilling spool and a 5,000 annular with a 10,000 rams.

MR. SMITH: Yes. Let it be entered into the record that that was under Conservation Order 170, Challenge Island, one exploratory well. And I think it would be well that the data presented for that conservation order be entered into the record. I have nothing further.

MR. KUGLER: I have no questions.

MR. HAMILTON: Thank you, Mr. Reiley.

MR. REILEY: Thank you.

MR. SMITH: I would recall John and do the same thing with him on Conservation Order 171. If I could ask another question of you, John. Has your company operated any wells in Alaska with this present configuration as proposed, the 5,000 annular on a 10,000 stack?

MR. WILLIS: Yes, sir, we have. We had that configuration on our Point Thompson #4 well or Point Thompson #3 well, and we also are currently rigging up a stack on our Alaska State C-1 well with that configuration. We have also received exception from the State for Point Thompson #6, Alaska State D-1 and E-1 wells under the new regulations. All of our previous wells are under the old regulations.

MR. SMITH: Okay, the new regulations are the current state regulations .....

MR. WILLIS: Right.

MR. SMITH: ..... amended (ph) in this year. The -- and the Point Thompson 6, Alaska State D and Alaska State E, I might point out for the record, were under -- granted under Conservation Order 171. And I'd like for the submittal of evidence for that record to be entered into this record.

MR. HAMILTON: Fine. Thank you.

MR. SMITH: Thank you, John.

MR. HAMILTON: That seems to be all the people we have here today that want to comment on the proposed amendments to the regulations. We'll close the hearing at this time, but I would like to repeat again that the hearing record will be kept open until December the 31st, 1980, at the close of business at 4:30 p.m. for additional comments. Thank you for attending.

E N D O F P R O C E E D I N G S

C E R T I F I C A T E

UNITED STATES OF AMERICA)
) ss.
STATE OF ALASKA)

I, Joyce Bigelow, Notary Public, in and for the State of Alaska, residing at Anchorage, Alaska, and Electronic Reporter for R & R Court Reporters, do hereby certify:

That the annexed and foregoing transcription of the Public Hearing of the Alaska Oil and Gas Conservation Commission, re: Conservation File No. 172, was taken before me on the 17th day of December, 1980, beginning at the hour of 9:40 a.m., in the Assembly Meeting Room, 3500 Tudor Road, Anchorage, Alaska, pursuant to notice of such said Public Hearing.

That this transcription of the Public Hearing of the Alaska Oil and Gas Conservation Commission, re: Conservation File No. 172, is a true and correct transcription of said Public Hearing, taken by me electronically and thereafter transcribed by me.

I am not a relative or employee or attorney or counsel of any parties at said Public Hearing, nor am I financially interested in this action.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal this 29th day of December, 1980.

Joyce Bigelow

S E A L

Notary Public in and for Alaska

My Commission expires 7/25/81

#3

NOTICE OF PUBLIC HEARING

STATE OF ALASKA ·
Alaska Oil Gas Conservation Commission

Conservation File No. 172

Re: The amendment of Title 20, AAC 25.035 of the Regulations as provided for in the Alaska Statutes, Title 31, Chapter 05, Article 1, Section 31.05.030 (c) and (d).

Notice is hereby given that the Alaska Oil and Gas Conservation Commission has found it necessary to amend Title 20, AAC 25.035 of the regulations. The regulation, as currently written, requires imprudent use of certain annular preventers when BOP stacks of 10M and 15M ratings are necessary. The proposed amendment in which Title 20 AAC 25.035 (c) (1) and (2) are substantially changed and Title 20 AAC 25.035 (c) (5) and (6) are amended is as follows:

(c) Blowout Prevention Equipment:

(1) before drilling below the surface casing, and until completed, a well must have remotely controlled BOP's, and the working pressure of the BOP's and associated equipment must exceed the maximum surface pressure to which they may be subjected except that the annular preventer need not have a working pressure rating greater than 5000 psig. The BOP stack arrangements shall be as follows:

(A) API 2M, 3M, and 5M stacks have at least three preventers, including one equipped with pipe rams that fit the size of drill pipe or casing being used, one with blind rams, and one annular type;

(B) API 10M and 15M stacks have at least four preventers, including two that fit the size of drill pipe or casing being used, one with blind rams and one annular type.

(2) information submitted with Form 10-401 must include the anticipated downhole pressures to be encountered, the maximum surface pressures to which the BOP equipment may be subjected, the criteria used to determine these pressures, and a well-control procedure which indicates how the preventers will be utilized for pressure control operations if the maximum surface pressures should exceed the rated working pressure of the annular preventer.

(5) the BOP equipment must include a drilling spool with [minimum two-inch] side outlets (if not on the blowout

preventer body), a minimum three-inch choke line and minimum two-inch choke manifold, a kill line, and a fillup line; the drilling string must contain full opening valves above and immediately below the kelly during all circulating operations using the kelly, with the necessary valve wrenches conveniently located on the rig floor; and

(6) two emergency valves with rotary subs for all connections in use and the necessary wrenches must be conveniently located on the drilling floor; one valve must be an inside [BOP of the] spring-loaded type; the second valve must be of the manually operated ball type, or equivalent valve.

A public hearing will be held in the Municipality of Anchorage Assembly Room, 3500 East Tudor Road, Anchorage, Alaska at 9:30 AM on Wednesday December 17, 1980.

Harry W. Kugler

Harry W. Kugler
Commissioner
Alaska Oil and Gas Conservation Commission

2. PUBLISHER

ADVERTISING ORDER

INVOICE MUST BE IN TRIPLICATE SHOWING ADVERTISING ORDER NO., CERTIFIED AFFIDAVIT OF PUBLICATION (PART 2 OF THIS FORM) WITH ATTACHED COPY OF ADVERTISEMENT MUST BE SUBMITTED WITH INVOICE.

DEPT. NO.	A.O. NO.
AO- 08	4052

PUBLISHER: Anchorage Times
840 West Fourth Avenue
Anchorage, Alasak 99501

VENDOR NO.

DATE OF A.O. November 12, 1980

DATES ADVERTISEMENT REQUIRED:

November 14, 1980

THE MATERIAL BETWEEN THE DOUBLE LINES MUST BE PRINTED IN ITS ENTIRETY ON THE DATES SHOWN.

FROM: Alaska Oil & Gas Conservation Commission
3001 Porcupine Drive
Anchorage, Alaska 99501

BILLING ADDRESS:

SAME

AFFIDAVIT-OF-PUBLICATION

UNITED STATES OF AMERICA
STATE OF Alaska } ss
third DIVISION.

BEFORE ME, THE UNDERSIGNED, A NOTARY PUBLIC THIS DAY PERSONALLY APPEARED Edith Yan WHO, BEING FIRST DULY SWORN, ACCORDING TO LAW, SAYS THAT HE/SHE IS THE Legal Clerk OF The Anchorage Times PUBLISHED AT Anchorage IN SAID DIVISION third AND STATE OF Alaska AND THAT THE ADVERTISEMENT, OF WHICH THE ANNEXED IS A TRUE COPY, WAS PUBLISHED IN SAID PUBLICATION ON THE 14th DAY OF November 1980, AND THEREAFTER FOR -0- CONSECUTIVE DAYS, THE LAST PUBLICATION APPEARING ON THE 14th DAY OF November 1980, AND THAT THE RATE CHARGED THEREON IS NOT IN EXCESS OF THE RATE
1x 9 1/2 inches $39.90 L79181
CHARGED PRIVATE INDIVIDUALS.

Ed Yan

SUBSCRIBED AND SWORN TO BEFORE ME THIS 17th DAY OF November 1980.

Patricia A. Gerlach

NOTARY PUBLIC FOR STATE OF Alaska
MY COMMISSION EXPIRES May 1st, 1982

RECEIVED
DEC 12 1980
Alaska Oil & Gas Cons. Commission
Anchorage

REMINDER—

ATTACH INVOICES AND PROOF OF PUBLICATION.

STATE OF ALASKA
NOTICE OF PUBLIC HEARING
STATE OF ALASKA
Alaska Oil Gas Conservation Commission
Conservation File No. 172

Re: The amendment of Title 20, AAC 25.035 of the Regulations as provided for in the Alaska Statutes, Title 31, Chapter 05, Article 1, Section 31.05.030 (c) and (d).

Notice is hereby given that the Alaska Oil and Gas Conservation Commmission has found it necessary to amend Title 20, AAC 25.035 of the regulations. The regulation, as currently written, requires imprudent use of certain annular preventers when BOP stacks of 10M and 15M ratings are necessary. The proposed amendment in which Title 20 AAC 25.035 (c) (1) and (2) are substantially changed and Title 20 AAC 25.035 (c) (5) and (6) are amended is as follows:

(c) Blowout Prevention Equipment:

(1) before drilling below the surface casing, and until completed, a well must have remotely controlled BOP's, and the working pressure of the BOP's and associated equipment must exceed the maximum surface pressure to which they may be subjected except that the annular preventer need not have a working pressure rating greater than 5000 psig. The BOP stack arrangements shall be as follows:

(A) API 2M, 3M, and 5M stacks have at least three preventers, including one equipped with pipe rams that fit the size of drill pipe or casing being used, one with blind rams, and one annular type;

(B) API 10M and 15M stacks have at least four preventers, including two that fit the size of drill pipe or casing being used, one with blind rams and one annular type.

(2) information submitted with Form 10-401 must include the anticipated downhole pressures to be encountered, the maximum surface pressures to which the BOP equipment may be subjected, the criteria used to determine these pressures, and a well-control procedure which indicates how the preventers will be utilized for pressure control operations if the maximum surface pressures should exceed the rated working pressure of the annular preventer.

(5) the BOP equipment must include a drilling spool with (minimum two-inch) side outlets (if not on the blowout preventer body), a minimum three-inch choke line and a minimum two-inch choke manifold, a kill line, and a fillup line; the drilling string must contain full opening valves above and immediately below the kelly during all circulating operations using the kelly, with the necessary valve wrenches conveniently located on the rig floor; and

(6) two emergency valves with rotary subs for all connections in use and the necessary wrenches must be conveniently located on the drilling floor; one valve must be an inside (BOP of the) spring-loaded type; the second valve must be the of the manually operated ball type, or equivalent valve.

A public hearing will be held in the Municipality of Anchorage Assembly Room, 3500 East Tudor Road, Anchorage, Alaska at 9:30 AM on Wednesday December 17, 1980.

/s/ Harry W. Kugler,
Commissioner
Alaska Oil and Gas
Conservation Commission

AO-08 4052

Pub: Nov. 14, 1980

#2

EXXON COMPANY, U.S.A.
POUCH 6601 • ANCHORAGE, ALASKA 99502

EXPLORATION DEPARTMENT
OFFSHORE/ALASKA DIVISION

COMM
COMM
RES ENG
1 ENG
2 ENG
3 ENG
4 ENG
1 GEOL
2 GEOL
3 GEOL
STAT TEC
STAT TEC
CONFER:
FILF:

October 24, 1980

Request for Variance to
Regulation 20AAC 25.035(C)(2)

Mr. Hoyle H. Hamilton, Chairman
State of Alaska
Oil & Gas Conservation Commission
3001 Porcupine Drive
Anchorage, Alaska 99501

Dear Mr. Hamilton:

In letters dated August 29, 1980, Exxon filed applications for permits to drill the following Arctic Slope wells:

1) Point Thomson Unit No. 6
2) Alaska State "D" No. 1
3) Alaska State "E" No. 1

As stated in the permit applications, Exxon plans to use a 13-5/8" inch 5000 psi working pressure annular BOP as part of the blowout preventer system whose other components are rated for 10,000 psi. Although this is in accord with widely accepted safe industry practice and with American Petroleum Institute guidlines, it is in technical violation of Miscellaneous Boards, Commission regulation 20 AAC 25.035 at paragraph (C)(2).

Exxon requests a variance to this regulation to allow use of the 5000 psi WP annular preventer on these four wells. A full discussion of the technical aspects of our position was recently submitted to you in the form of a letter requesting revision of the subject regulation. This letter is included as an attachment for your reference in considering this request.

Very truly yours,

Robert K. Riddle

RAM:jrh
240-500-200

KHM

COPY

EXXON COMPANY, U.S.A.
POUCH 6601 • ANCHORAGE, ALASKA 99502 (907) 276-4552

ALASKA OPERATIONS
WESTERN DIVISION

W. MONTE TAYLOR
OPERATIONS MANAGER

September 23, 1980

State of Alaska
Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, AK 99501

Gentlemen:

Exxon requests revision of the recently enacted Miscellaneous Boards, Commissions regulation 20 AAC 25.035 Blowout Prevention Equipment which at paragraph (c) (2) requires, in part, "the working pressure of any BOP and associated equipment must exceed the maximum surface pressure to which they may be subjected;..."

On the surface, this appears to be an entirely reasonable requirement and little or no comment was raised during the review period prior to enactment. Careful consideration now reveals that the requirement is contrary to existing prudent drilling practice since "any BOP" includes the annular preventer whose working pressure might be required to exceed 5,000 psi depending upon interpretation of the undefined term "maximum surface pressure" and the unclear wording "to which they may be subjected."

Current safe BOP selection practice for drilling higher pressure wells entails selection of ram-type preventers with a working pressure exceeding the anticipated surface pressure for any casing on which they are installed and selection of the annular preventer to exceed the anticipated surface pressure which would be encountered in well control operations. The intended use of the annular preventer is to provide initial closure on any part of a drill string at relatively low pressure, in the event of a well kick, to permit the operator to analyze the problem. The operator would then proceed with well control operations using the ram-type preventers and/or the annular preventer depending on pressures and the condition of the well. With current technology in equipment, abnormal pressure detection and well control training, the initial pressure will normally not exceed 1,000 to 2,000 psi, and if well control procedures result in pressures in excess of 2,000 to 2,500 psi, prudent operating practice is to conduct the well control operation using the ram-type preventers thus effectively isolating the annular preventer from the higher pressure. That is to say, the annular preventer would not be subjected to pressures exceeding 5,000 psi.

There have been no documented operational instances where an annular preventer having a working pressure greater than 5,000 psi would have prevented a blowout, yet literal interpretation of the subject regulation could result in the requirement for such a preventer. By design and operational usage, an annular preventer is intended to provide for a limited range of functions under low to moderate pressure, i.e., less than 5,000 psi. A regulatory requirement for a greater than 5,000 psi working pressure annular preventer distorts the purpose and operational usage of the annular preventer, potentially jeopardizing well control and safety under high pressures. Moreover, it is projected that several years would be required to design, shop test, and operationally validate the reliability of 10,000 psi annular preventers of the 16-3/4 inch or 18-5/8 inch sizes required in some drilling programs. This regulation could limit the availability of rigs for scheduled exploration drilling programs, require use of prototype equipment during well control operations, and result in no tangible advancement in technology or increased safety.

Attached for your review is a general discussion of blowout preventer equipment and the use of preventers in well control.

In view of the problems discussed above, Exxon requests that 20 AAC 25.035(c) (2) be revised as follows:

> "the working pressure of any ram-type BOP and associated equipment must exceed the anticipated surface pressure of any casing string on which it is to be used and the working pressure of any annular BOP must exceed the pressure to which it may be subjected in well control operations; information submitted with Form 10-401 must include anticipated formation pressures to be encountered, the anticipated surface pressure for each casing string, anticipated pressures to which the annular preventer may be subected in well control operations, and the criteria used to determine these pressures consistent with 20 AAC 25.030 Casing and Cementing;

We believe the above requirement more clearly states the established criteria for selection of BOP equipment and will allow for the differing methods of program design now used by industry. Although we realize that your decision must be based on the merits of the case, we would like to point out a recent precedent involving a USGS OCS regulation. This was a BOP requirement essentially identical to 20 AAC 25.035 (c) (2) which was revised along the lines proposed. Your consideration of this proposed revision is respectfully requested.

USGS?
not really

Yours very truly,

W. Monte Taylor

W. Monte Taylor

TLP/RAM/kb
Attachment
28-Z

GENERAL DESCRIPTION OF BLOWOUT PREVENTER EQUIPMENT AND USAGE

A blowout preventer (BOP) system consists of several engineering designed components that can be systematically operated in the event of unexpected flow from a well. The BOP system is used initially to close a well in, and thereafter to hold back pressure on the wellbore, while circulating a mud weight of sufficient hydrostatic pressure under controlled conditions to overcome the influx.

Figure 1 is a schematic of a BOP system, commonly referred to as a BOP stack. The basic components are similar: a wellhead connection to the previously set and cemented casing strings; pipe ram preventers; blind ram; an annular preventer; and a system of lines and valves to direct fluid into or out of the BOP when various components of the system are functioned for well control operations. The number and position of the pipe rams and blind ram may vary with particular requirements of a given well, the operator's well control procedures, and to some extent, on the complexity of the BOP system. The size, shape and control of the BOP system are specifically designed for a particular rig. Major changes to a BOP stack often involve changes in handling procedures and auxiliary rig equipment.

The pipe rams, blind ram, and annular preventers are designed and used primarily for closing and sealing functions. They also have features that provide for redundancy and secondary functions. Figure 2 is a schematic of the primary sealing method of the pipe rams, blind ram, and annular preventer.

Pipe rams are semicircular concave faced components having primary sealing surfaces designed to match the outside diameter of the particular pipe in use. Blind rams are solid faced components, with elastic and metal sealing surfaces for closure and sealing with nothing opposite the ram. Some blind rams are equipped with pipe shearing blades which can close, shear, and effect a seal. The rams are opened and closed by positive controlled operating fluid applied to the ram piston.

The annular preventer is equipped with a large ring of elastic sealing material (rubber or neoprene) designed to close on open hole or around any size or shape pipe. The primary closing method is positive operating pressure applied to a shaped piston resulting in a "squeezing out" effect of the elastic element. Depending on the design of particular annular preventers, wellbore pressure from below may also act on the piston to "pressure assist" the squeezing of the element. The primary opening control method is positive operating pressure applied to the shaped piston to reverse its travel and allow the element to relax to its normal configuration. The significance of the designed operational features of the annular preventer is discussed below.

OPERATIONS

During normal drilling operations, control of the well is maintained by using adequate hydrostatic pressure from the mud column in the wellbore, monitoring of various drilling parameters, and through proper crew training.

As stated previously, the blowout preventer system allows for closing in a well when unexpected flow occurs. The BOP unit is intended to provide the operator with a series of alternative operational functions, by use of the individual components, to control the influx by circulating fluid in the wellbore. The control of the wellbore depends on properly designed equipment, prudent operation of the equipment, and proper training of personnel performing the task.

Pipe rams are considered the primary means of sealing around drill pipe and the blind rams for sealing on open hole. Recognizing the adverse mechanical effect that could occur if the pipe rams were closed on other than their designed pipe size or if the blind rams were closed on other than open hole, the annular preventer was designed to allow initial closing around irregular sizes and shapes. It is, therefore, generally the first preventer to be closed in an emergency. Well control can then be transitioned in an orderly fashion to the primary pipe rams for long term sealing and operational control.

Figure 3 is the closing-in procedure employed by Exxon. It is similar to the procedure used by any prudent drilling operator. Figure 4 represents calculations of various conditions of gas influx that would have to occur prior to closing the annular preventer in order for it to be subjected to initial pressure greater than 5,000 psi. With operators and crews trained for abnormal pressure detection and well control in accordance with current standards, the likelihood of unexpected flow of the intensity and volume reflected by the example is extremely remote. For example, the pit volume increase alarm normally would have a sensitivity of 10 bbl or less. Response time for a trained drilling crew to check the well for flow and properly close the annular preventer is two min. or less. Assuming an influx rate equivalent to 20,000 bbl per day, the total influx prior to shut in would be 38 bbl, which is much less than the values shown in Figure 4. Accordingly, the annular preventer would not be subjected to initial closed-in pressures greater than 5,000 psi. After close-in, if the operator reasonably anticipates surface pressures exceeding about 2,500 psi, the pipe rams are routinely used for primary sealing and control. Functioning of either of the pipe rams or blind rams will isolate the annular preventer from any subsequent high well pressures that might occur during control operations.

A secondary feature designed for and operationally engineered into the use of a blowout preventer system (the primary function is again to provide sealing) is the ability of moving pipe into or out of the wellbore under pressure. This procedure, called "stripping", is not a common occurrence during well control but is a desirable alternative to have available under some circumstances. It can be safely handled with existing components of the BOP system and trained crews. In some situations, stripping can be performed with the pipe rams or with the annular preventer or with a combination of the preventers. Due to its infrequent occurrence, the stripping procedure is generally employed only after considerable forethought and planning. Figure 5 shows a fundamental calculation to determine if stripping is a viable alternative. If there is an insufficient downward force (from the weight of the pipe already in the hole) to overcome the upward force generated by the unexpected influx, stripping cannot be performed and snubbing operations become the alternative. This is a less frequent occurrence and specialty companies and equipment are necessary to perform the procedure.

If stripping is a viable and necessary option, a historical preference, under low wellbore pressure, has been to strip with the annular preventer. This procedure is somewhat less complicated, <u>under low pressures</u>, and reduces the possibility of damage to the primary sealing ram preventers that would be used for subsequent control operations once stripping has been completed.

A generalized discussion of stripping with an annular preventer is presented in this paragraph. Recall that the annular preventer has a ring of elastic material, squeezed by a shaped piston upon application of pressure from the control accumulator and/or by wellbore pressure assist. The higher the well pressure, the tighter the element is squeezed to maintain a pressure seal. As pipe is moved through the annular preventer, friction from the pipe body and the passage of the larger OD pipe tool joints causes wear of the element. The higher the wellbore pressure and the required closing pressure, the greater the wear. The greater the wear, the greater the closing pressure must be to maintain a seal.

For the annular preventer designed with well pressure assisting hydraulic closing pressure, the closing pressure can be reduced to minimize friction (and thus wear) between the element and the pipe and tool joint. At relatively high wellbore pressures (2,000 to 2,500 psi), the hydraulic closing pressure can no longer be reduced sufficiently to prevent excessive wear due to pipe movement through the element. Depending on the size of the annular preventer and pipe in use, <u>opening</u> pressure instead of closing pressure would have to be applied to the preventer to avoid excessive element friction and wear. Applying opening pressure is considered to be an extremely hazardous procedure since a fluctuation in well pressure could allow the preventer to suddenly open. Even if the pipe rams were immediately closed, uncontrolled flow could jeopardize rig and crew safety. It would be a matter of chance at this time whether a tool joint were opposite the closing pipe ram thus damaging it beyond subsequent sealing capability.

For the annular preventer designed without wellbore assist, increasingly higher hydraulic closing pressures are required to maintain the seal at higher and higher well pressures. Figure 6 shows results of shop tests of the wear on an element (stripping cycles to failure) relative to increasing wellbore pressure and the resulting increase in closing pressure. Note the drastic reduction in element life when well pressure is increased from 1,500 to 3,000 psi. While the results of the tests may vary somewhat among preventers, the size pipe used or the type of element installed, it is Exxon's position that the test is strongly indicative of the results that will be obtained at higher well pressures. In other words, the stripping wear life of an annular preventer is greatly reduced at increased wellbore pressures. Of equal significance is the need for the element to maintain its sealing capability when repeatedly moving the smaller diameter pipe body, then the larger diameter tool joint and then the smaller diameter pipe body again through the preventer. The element's ability to maintain a seal under this procedure is related to the amount of wear and pressure to which it is subjected. Although a provision is available for "slightly" reducing the amount of closing force on the element as the tool joint starts through, the opening and closing sequences of an annular preventer are not totally positive. This is due to the larger sealing and piston areas involved, the amount of probable wear, and the relatively large fluid operating volumes.

For these reasons, it is Exxon's normal policy not to attempt stripping operations using an annular preventer, regardless of its pressure rating, when well pressure exceeds 2,000 to 2,500 psi. Our practice is supported by the experience of Otis Engineering Corporation's worldwide stripping and snubbing operations. Otis' views on the subject are reflected in their letter of February 11, 1980, Figure 7. Supporting documentation can also be found in API Recommended Practices for Blowout Prevention Equipment Systems RP53 Page 14, Figure 8. Preventer system arrangements for 5,000, 10,000, and 15,000 psi pressure ratings may utilize annular preventers rated for 5,000 psi.

In summary, by design and operational usage, an annular preventer is intended to provide for a limited range of functions under low to moderate pressure, i.e., less than 5,000 psi. A regulatory requirement for a greater than 5,000 psi working pressure annular preventer distorts the purpose and operational usage of the annular preventer, potentially jeopardizing well control and safety under high pressures. Moreover, it is projected that several years would be required to design, shop test, and operationally validate the reliability of 10,000 psi annular preventers of the 16-3/4 inch or 18-5/8 inch sizes required in some drilling programs. This regulation could limit the availability of rigs for scheduled exploration drilling programs, require use of prototype equipment during well control operations, and result in no tangible advancement in technology or increased safety.

TLP/RAM/rms
211-A

TYPICAL BLOWOUT PREVENTER STACK

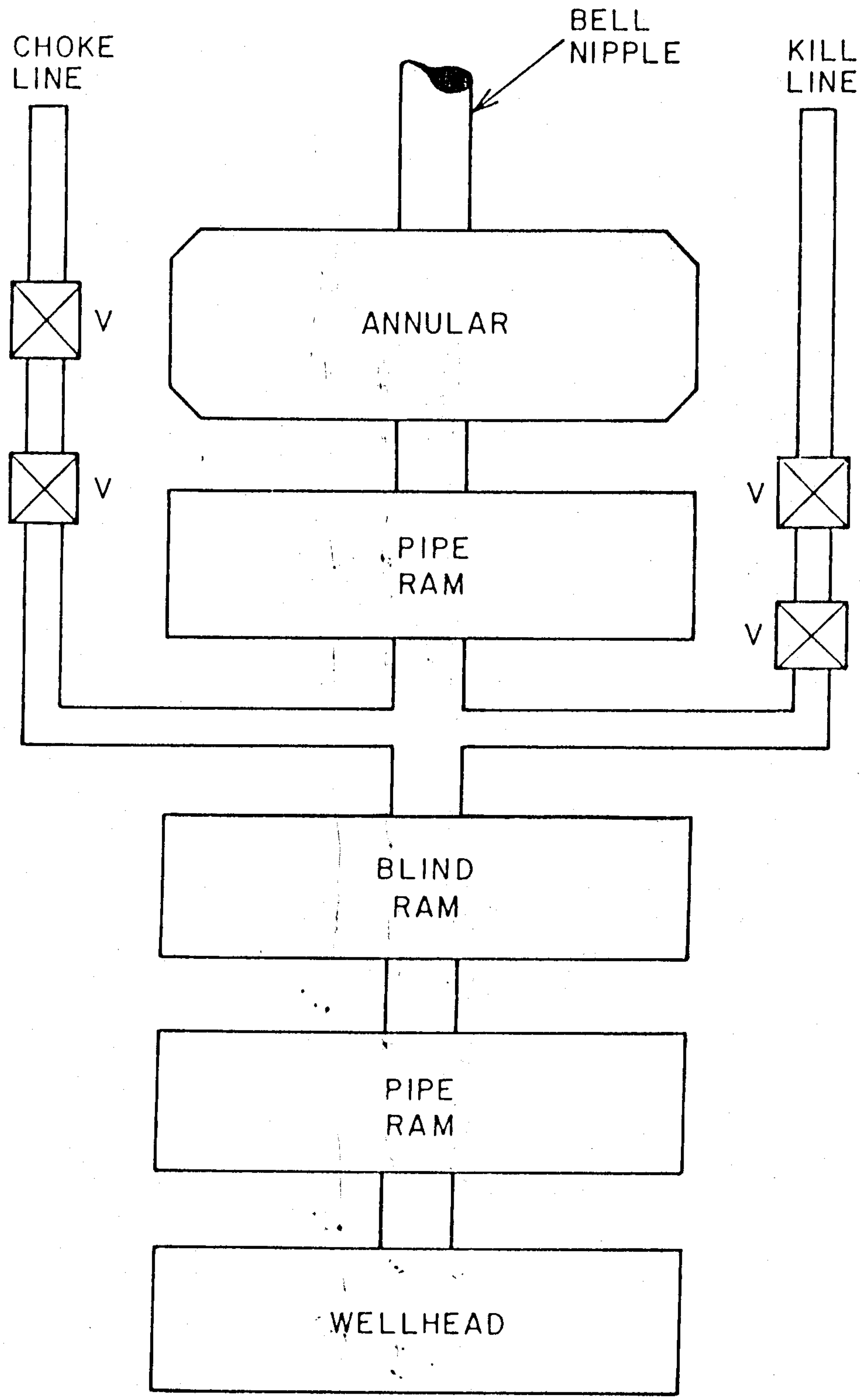

FIGURE I

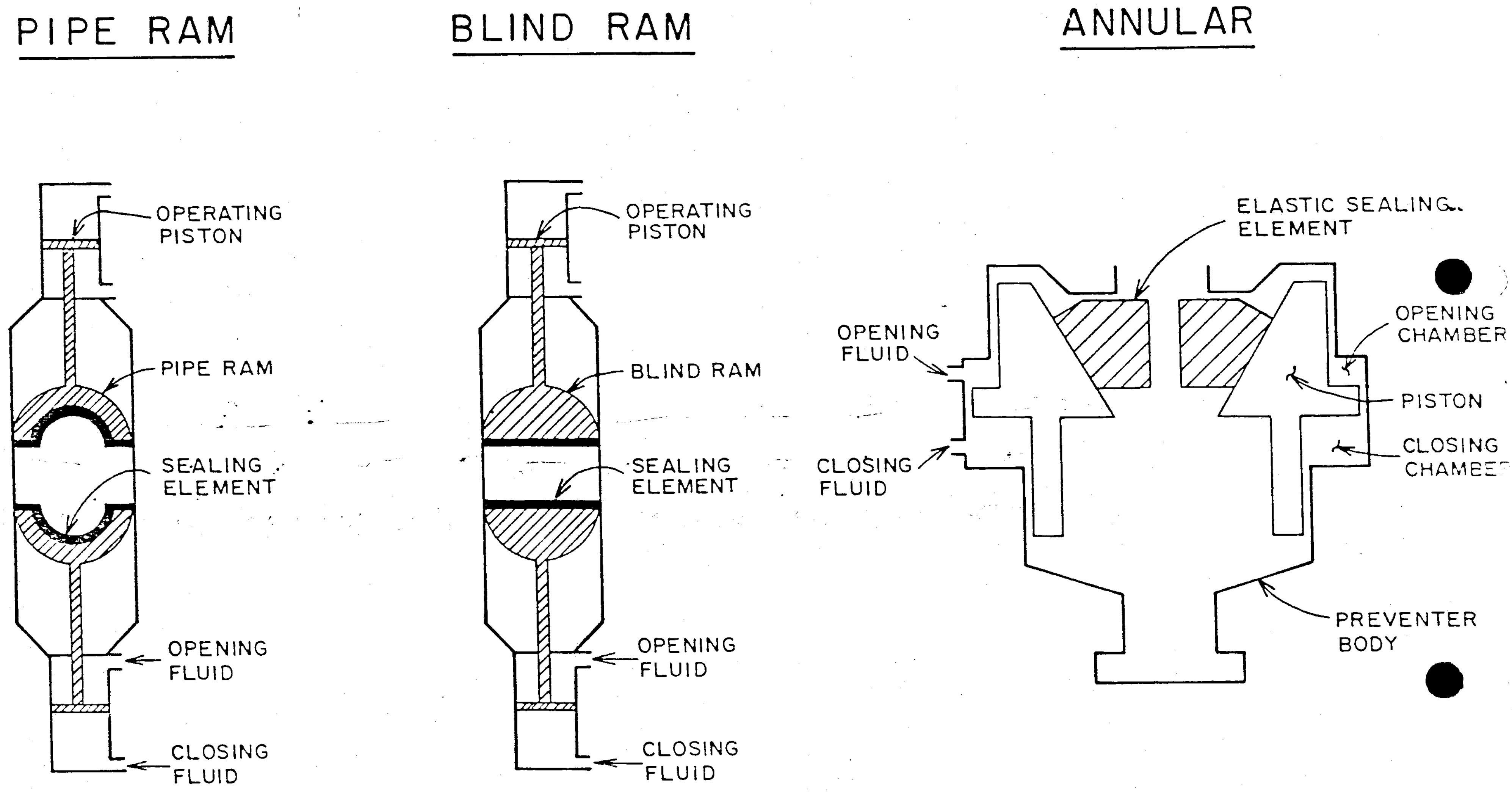
PIPE RAM
OPERATING PISTON
PIPE RAM
SEALING ELEMENT
OPENING FLUID
CLOSING FLUID
BLIND RAM
OPERATING PISTON
BLIND RAM
SEALING ELEMENT
OPENING FLUID
CLOSING FLUID
ANNULAR
ELASTIC SEALING ELEMENT
OPENING FLUID
CLOSING FLUID
OPENING CHAMBER
PISTON
CLOSING
PREVENTER BODY

FIGURE 2

LAND, PLATFORM & JACK-UP OPERATION

FULL BOP STACK ON COMPETENT CASING
CLOSING-IN PROCEDURE

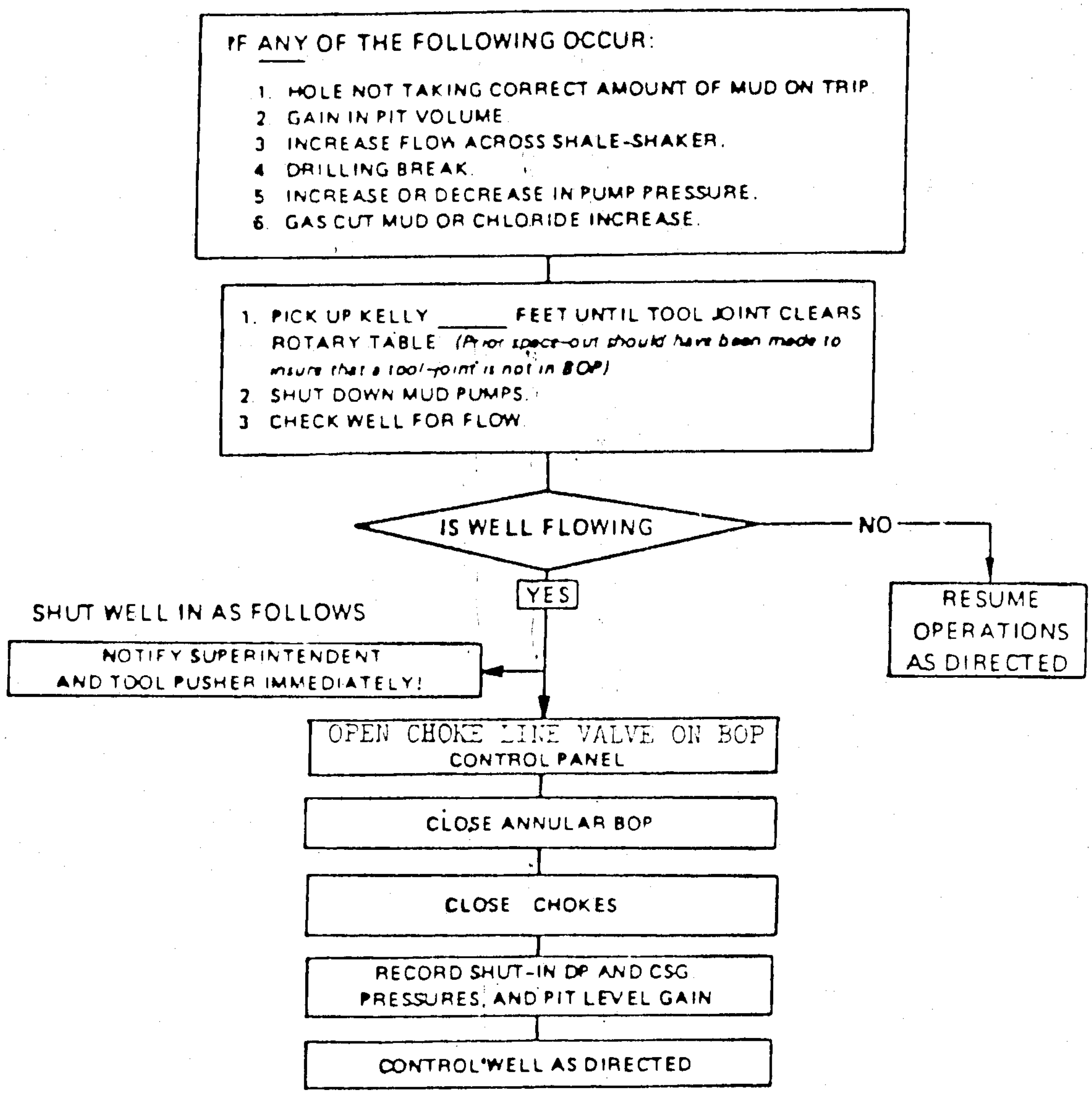

FIGURE 3

REQUIRED INFLUX
FOR INITIAL WELL SHUT-IN PRESSURE
TO EQUAL 5,000 PSI

Well TD-Ft	Drilling Mud Wt-ppg	Barrels of Gas Influx With A 2 ppg Kick	Barrels of Gas Influx With A 4 ppg Kick
13,000	10.0	389	242
15,000	12.0	293	156
17,000	14.0	227	98

WELLBORE CONFIGURATION

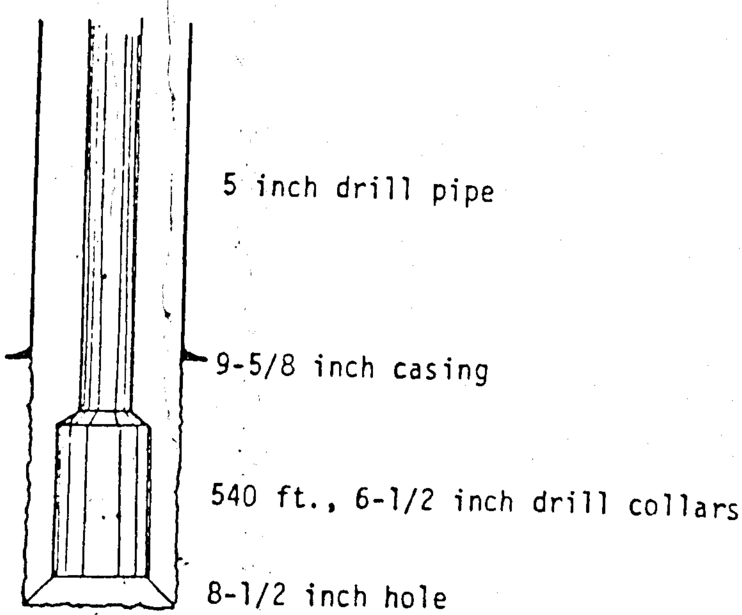

Figure 4

LENGTH OF PIPE REQUIRED TO STRIP THROUGH ANNULAR Vs WELLBORE PRESSURE

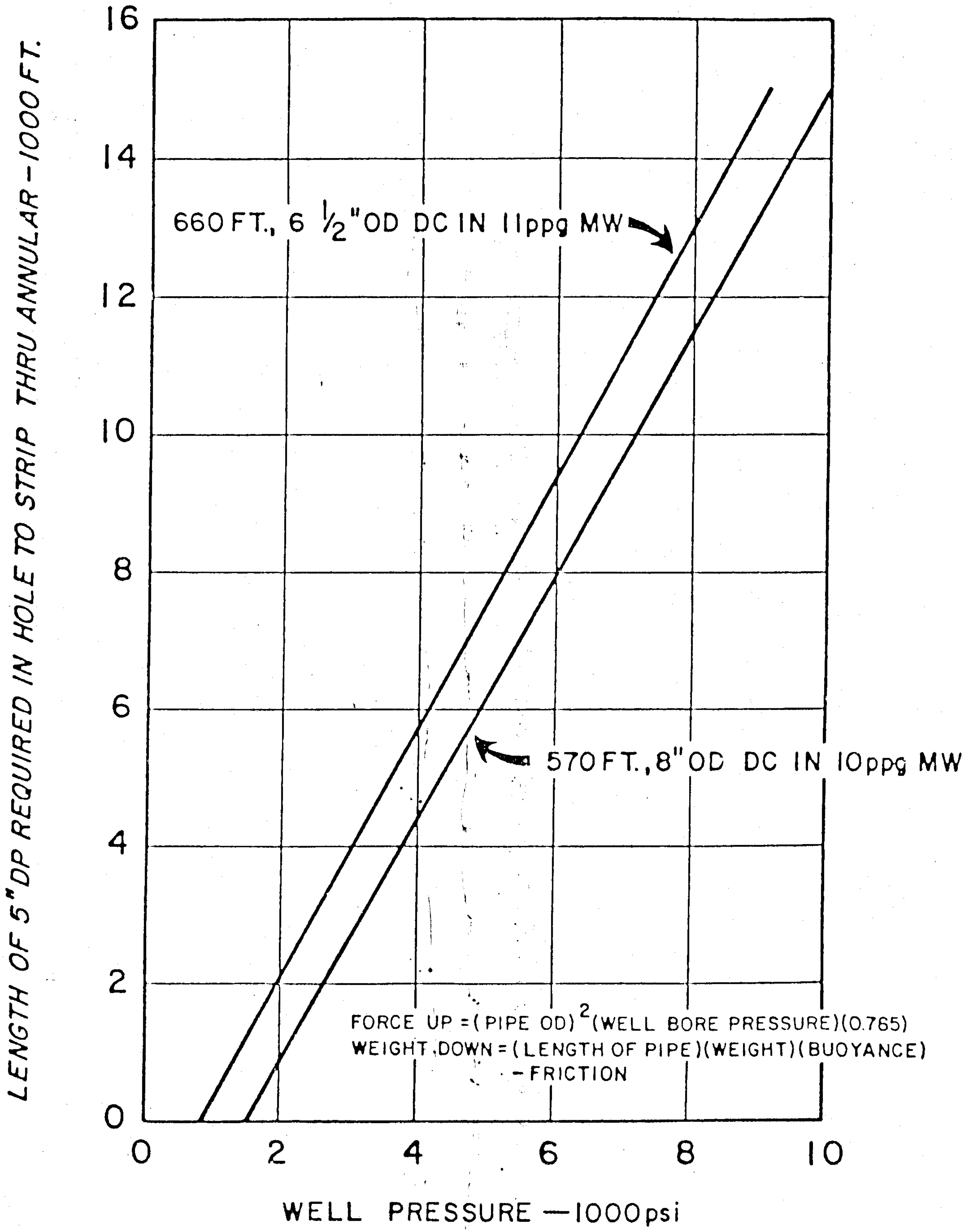

FIGURE 5

STRIPPING TEST RESULTS

18 3/4" AND 16 3/4"- 5000 PSI ANNULAR

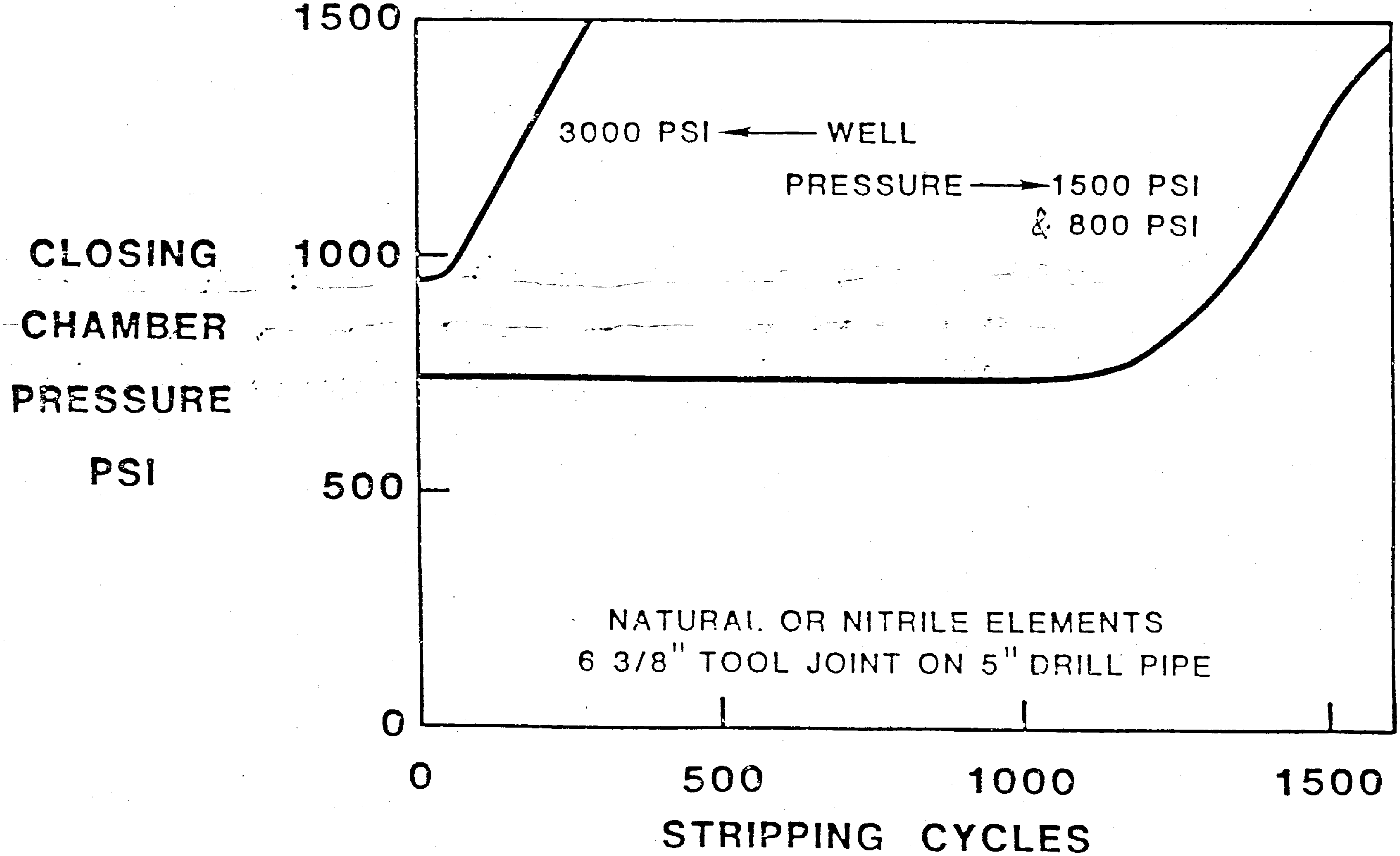

FIGURE 6

OTIS

P. O. BOX 34380 · DALLAS, TEXAS 75234
AREA CODE 214-242-8088

PHILLIP S. SIZER, P.E.
SENIOR VICE PRESIDENT
TECHNICAL DIRECTOR

February 11, 1980

Mr. H. J. Flatt
Exxon Headquarters
Drilling Manager
Exxon Company, U.S.A.
P. O. Box 2180
Room 3005
Houston, TX 77001

Dear Sir:

With reference to your inquiry regarding the use of large bore annular preventers, Otis has had no experience stripping pipe using any annular type preventer above 10 3/4 I.D. We have had some experiences down through the years with emergency stripping of drill pipe, sizes 3 1/2 through 4 1/2, using the 7 1/16 I.D. annular preventer under 3,000 psi, but in each case we either had adequate pipe in the hole or our conventional snubbing equipment available for stripping purposes.

We regularly strip 1.315 O.D. through 2 7/8" O.D. using a pre-sized, molded stripper element similar to Hydril's RS Stripper, Composite Catalog, Page 3674. Most routine offshore workover is conducted with 1.315 O.D. pipe stripped through a molded stripper element sized to fit 4 1/16 bore equipment, 3,000 psi maximum.

We have used dual element stripping techniques but employ this method to lengthen element life as opposed to increasing working pressure ranges. Stripping with either the molded or annular type presents major problems when considering the change in areas as the joint upset moves through the seal area from two standpoints: 1) Sufficient pipe weight must be present to pull the joint through the seal area, and 2) Strict attention must be placed on the type of joint used. No square shoulders must be present and a very shallow angle must be used for the diameter transition.

I would suggest that smaller pipe diameters in relation to large bore annular preventers could present a problem unless the elastomeric material is adequately backed up by metal. One other concern is the tendency for the elastomeric materials to flow easily when the pressure differential approaches or exceeds the modulus of elasticity. This means that without near perfect metal backup, higher pressure sealing is not practical. We experience a certain amount of difficulty in the ram type preventer as well, and must be constantly aware of and accommodating to the metal backup configuration.

Figure 7

One point I should mention is, the industry also uses the term stripping to indicate the movement of pipe through ram type BOP's. I have assumed in your inquiry we are talking about annular type equipment as opposed to ram type equipment.

Our principal experience has been with ram type equipment, using pipe sizes up through 7" O.D. and pressure up through 18,000 psi. The large pipe has been stripped with ram type BOP's against 2,000 psi and the smallest pipe has been associated with ram type BOP's and 18,000 psi.

We would, if required to rig up on an existing stack, test all BOP's including the annular to rated working pressure but would not attempt to strip more than 5,000 psi using a 7-1/16 I.D. annular preventer. We believe increases in bore will reduce this maximum drastically as 18 3/4 I.D. is reached.

I hope the foregoing is useful in helping you arrive at a decision but if additional information is necessary, please contact me.

Yours very truly,

OTIS ENGINEERING CORPORATION

Phillip S. Sizer

Phillip S. Sizer

PSS:mc

cc: Mr. Homer Davis

Figure 8

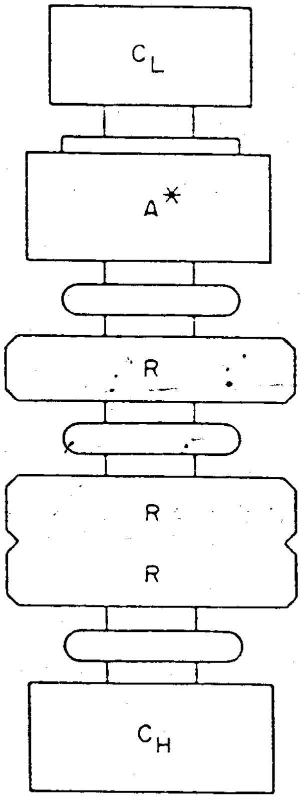

FIG. 2.D.4

ARRANGEMENT $C_HR_dRA^*C_L$
Triple Ram Type Preventers, R_t, Optional.

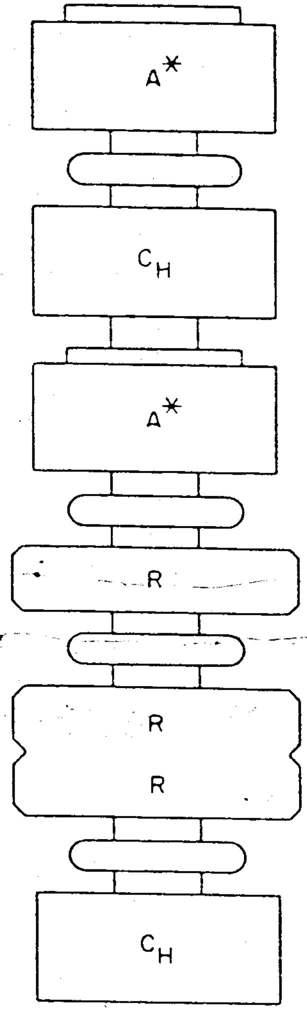

FIG. 2.D.5

ARRANGEMENT $C_HR_dRA^*C_HA^*$

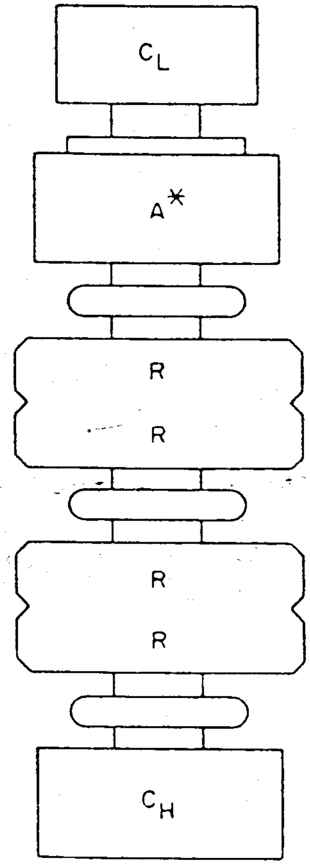

FIG. 2.D.6

ARRANGEMENT
$C_HR_dR_dA^*C_L$

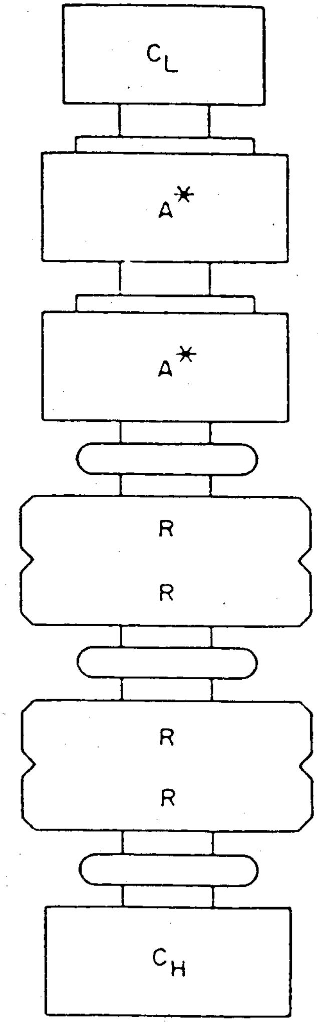

FIG. 2.D.7

ARRANGEMENT
$C_HR_dR_dA^*A^*C_L$

*Annular preventer, A, may have 5M working pressure rating.

TYPICAL BLOWOUT PREVENTER ARRANGEMENTS FOR 5M, 10M, AND 15M RATED WORKING PRESSURE SERVICE — SUBSEA INSTALLATION

#1

EXXON COMPANY, U.S.A.
POUCH 6601 • ANCHORAGE, ALASKA 99502 (907) 276-4552

ALASKA OPERATIONS
WESTERN DIVISION

W. MONTE TAYLOR
OPERATIONS MANAGER

COMM	
COMM	
COMM	
RES ENG	
1 ENG	Blair
2 ENG	
3 ENG	
4 ENG	
1 GEOL	
2 GEOL	
3 GEOL	
STAT TEC	
STAT TEC	
CONFER:	
FILF:	

September 23, 1980

State of Alaska
Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, AK 99501

Gentlemen:

Exxon requests revision of the recently enacted Miscellaneous Boards, Commissions regulation 20 AAC 25.035 Blowout Prevention Equipment which at paragraph (c) (2) requires, in part, "the working pressure of any BOP and associated equipment must exceed the maximum surface pressure to which they may be subjected;..."

On the surface, this appears to be an entirely reasonable requirement and little or no comment was raised during the review period prior to enactment. Careful consideration now reveals that the requirement is contrary to existing prudent drilling practice since "any BOP" includes the annular preventer whose working pressure might be required to exceed 5,000 psi depending upon interpretation of the undefined term "maximum surface pressure" and the unclear wording "to which they may be subjected."

Current safe BOP selection practice for drilling higher pressure wells entails selection of ram-type preventers with a working pressure exceeding the anticipated surface pressure for any casing on which they are installed and selection of the annular preventer to exceed the anticipated surface pressure which would be encountered in well control operations. The intended use of the annular preventer is to provide initial closure on any part of a drill string at relatively low pressure, in the event of a well kick, to permit the operator to analyze the problem. The operator would then proceed with well control operations using the ram-type preventers and/or the annular preventer depending on pressures and the condition of the well. With current technology in equipment, abnormal pressure detection and well control training, the initial pressure will normally not exceed 1,000 to 2,000 psi, and if well control procedures result in pressures in excess of 2,000 to 2,500 psi, prudent operating practice is to conduct the well control operation using the ram-type preventers thus effectively isolating the annular preventer from the higher pressure. That is to say, the annular preventer would not be subjected to pressures exceeding 5,000 psi.

RECEIVED
OCT 20 1980
Alaska Oil & Gas Cons. Commission
Anchorage

There have been no documented operational instances where an annular preventer having a working pressure greater than 5,000 psi would have prevented a blowout, yet literal interpretation of the subject regulation could result in the requirement for such a preventer. By design and operational usage, an annular preventer is intended to provide for a limited range of functions under low to moderate pressure, i.e., less than 5,000 psi. A regulatory requirement for a greater than 5,000 psi working pressure annular preventer distorts the purpose and operational usage of the annular preventer, potentially jeopardizing well control and safety under high pressures. Moreover, it is projected that several years would be required to design, shop test, and operationally validate the reliability of 10,000 psi annular preventers of the 16-3/4 inch or 18-5/8 inch sizes required in some drilling programs. This regulation could limit the availability of rigs for scheduled exploration drilling programs, require use of prototype equipment during well control operations, and result in no tangible advancement in technology or increased safety.

Attached for your review is a general discussion of blowout preventer equipment and the use of preventers in well control.

In view of the problems discussed above, Exxon requests that 20 AAC 25.035(c) (2) be revised as follows:

> "the working pressure of any ram-type BOP and associated equipment must exceed the anticipated surface pressure of any casing string on which it is to be used and the working pressure of any annular BOP must exceed the pressure to which it may be subjected in well control operations; information submitted with Form 10-401 must include anticipated formation pressures to be encountered, the anticipated surface pressure for each casing string, anticipated pressures to which the annular preventer may be subected in well control operations, and the criteria used to determine these pressures consistent with 20 AAC 25.030 Casing and Cementing;

We believe the above requirement more clearly states the established criteria for selection of BOP equipment and will allow for the differing methods of program design now used by industry. Although we realize that your decision must be based on the merits of the case, we would like to point out a recent precedent involving a USGS OCS regulation. This was a BOP requirement essentially identical to 20 AAC 25.035 (c) (2) which was revised along the lines proposed. Your consideration of this proposed revision is respectfully requested.

Yours very truly,

W. Monte Taylor

W. Monte Taylor

TLP/RAM/kb
Attachment
28-Z

cc: R. K. Riddle

GENERAL DESCRIPTION OF BLOWOUT PREVENTER EQUIPMENT AND USAGE

A blowout preventer (BOP) system consists of several engineering designed components that can be systematically operated in the event of unexpected flow from a well. The BOP system is used initially to close a well in, and thereafter to hold back pressure on the wellbore, while circulating a mud weight of sufficient hydrostatic pressure under controlled conditions to overcome the influx.

Figure 1 is a schematic of a BOP system, commonly referred to as a BOP stack. The basic components are similar: a wellhead connection to the previously set and cemented casing strings; pipe ram preventers; blind ram; an annular preventer; and a system of lines and valves to direct fluid into or out of the BOP when various components of the system are functioned for well control operations. The number and position of the pipe rams and blind ram may vary with particular requirements of a given well, the operator's well control procedures, and to some extent, on the complexity of the BOP system. The size, shape and control of the BOP system are specifically designed for a particular rig. <u>Major changes to a BOP stack often involve changes in handling procedures and auxiliary rig equipment</u>.

The pipe rams, blind ram, and annular preventers are designed and used primarily for closing and sealing functions. They also have features that provide for redundancy and secondary functions. Figure 2 is a schematic of the primary sealing method of the pipe rams, blind ram, and annular preventer.

Pipe rams are semicircular concave faced components having primary sealing surfaces designed to match the outside diameter of the particular pipe in use. Blind rams are solid faced components, with elastic and metal sealing surfaces for closure and sealing with nothing opposite the ram. Some blind rams are equipped with pipe shearing blades which can close, shear, and effect a seal. The rams are opened and closed by positive controlled operating fluid applied to the ram piston.

The annular preventer is equipped with a large ring of elastic sealing material (rubber or neoprene) designed to close on open hole or around any size or shape pipe. The primary closing method is positive operating pressure applied to a shaped piston resulting in a "squeezing out" effect of the elastic element. Depending on the design of particular annular preventers, wellbore pressure from below may also act on the piston to "pressure assist" the squeezing of the element. The primary opening control method is positive operating pressure applied to the shaped piston to reverse its travel and allow the element to relax to its normal configuration. The significance of the designed operational features of the annular preventer is discussed below.

OPERATIONS

During normal drilling operations, control of the well is maintained by using adequate hydrostatic pressure from the mud column in the wellbore, monitoring of various drilling parameters, and through proper crew training.

As stated previously, the blowout preventer system allows for closing in a well when unexpected flow occurs. The BOP unit is intended to provide the operator with a series of alternative operational functions, by use of the individual components, to control the influx by circulating fluid in the wellbore. The control of the wellbore depends on properly designed equipment, prudent operation of the equipment, and proper training of personnel performing the task.

Pipe rams are considered the primary means of sealing around drill pipe and the blind rams for sealing on open hole. Recognizing the adverse mechanical effect that could occur if the pipe rams were closed on other than their designed pipe size or if the blind rams were closed on other than open hole, the annular preventer was designed to allow initial closing around irregular sizes and shapes. It is, therefore, generally the first preventer to be closed in an emergency. Well control can then be transitioned in an orderly fashion to the primary pipe rams for long term sealing and operational control.

Figure 3 is the closing-in procedure employed by Exxon. It is similar to the procedure used by any prudent drilling operator. Figure 4 represents calculations of various conditions of gas infux that would have to occur prior to closing the annular preventer in order for it to be subjected to initial pressure greater than 5,000 psi. With operators and crews trained for abnormal pressure detection and well control in accordance with current standards, the likelihood of unexpected flow of the intensity and volume reflected by the example is extremely remote. For example, the pit volume increase alarm normally would have a sensitivity of 10 bbl or less. Response time for a trained drilling crew to check the well for flow and properly close the annular preventer is two min. or less. Assuming an influx rate equivalent to 20,000 bbl per day, the total influx prior to shut in would be 38 bbl, which is much less than the values shown in Figure 4. Accordingly, the annular preventer would not be subjected to initial closed-in pressures greater than 5,000 psi. After close-in, if the operator reasonably anticipates surface pressures exceeding about 2,500 psi, the pipe rams are routinely used for primary sealing and control. Functioning of either of the pipe rams or blind rams will isolate the annular preventer from any subsequent high well pressures that might occur during control operations.

A secondary feature designed for and operationally engineered into the use of a blowout preventer system (the primary function is again to provide sealing) is the ability of moving pipe into or out of the wellbore under pressure. This procedure, called "stripping", is not a common occurrence during well control but is a desirable alternative to have available under some circumstances. It can be safely handled with existing components of the BOP system and trained crews. In some situations, stripping can be performed with the pipe rams or with the annular preventer or with a combination of the preventers. Due to its infrequent occurrence, the stripping procedure is generally employed only after considerable forethought and planning. Figure 5 shows a fundamental calculation to determine if stripping is a viable alternative. If there is an insufficient downward force (from the weight of the pipe already in the hole) to overcome the upward force generated by the unexpected influx, stripping cannot be performed and snubbing operations become the alternative. This is a less frequent occurrence and specialty companies and equipment are necessary to perform the procedure.

If stripping is a viable and necessary option, a historical preference, under low wellbore pressure, has been to strip with the annular preventer. This procedure is somewhat less complicated, <u>under low pressures</u>, and reduces the possibility of damage to the primary sealing ram preventers that would be used for subsequent control operations once stripping has been completed.

A generalized discussion of stripping with an annular preventer is presented in this paragraph. Recall that the annular preventer has a ring of elastic material, squeezed by a shaped piston upon application of pressure from the control accumulator and/or by wellbore pressure assist. The higher the well pressure, the tighter the element is squeezed to maintain a pressure seal. As pipe is moved through the annular preventer, friction from the pipe body and the passage of the larger OD pipe tool joints causes wear of the element. The higher the wellbore pressure and the required closing pressure, the greater the wear. The greater the wear, the greater the closing pressure must be to maintain a seal.

For the annular preventer designed with well pressure assisting hydraulic closing pressure, the closing pressure can be reduced to minimize friction (and thus wear) between the element and the pipe and tool joint. At relatively high wellbore pressures (2,000 to 2,500 psi), the hydraulic closing pressure can no longer be reduced sufficiently to prevent excessive wear due to pipe movement through the element. Depending on the size of the annular preventer and pipe in use, <u>opening</u> pressure instead of closing pressure would have to be applied to the preventer to avoid excessive element friction and wear. Applying opening pressure is considered to be an extremely hazardous procedure since a fluctuation in well pressure could allow the preventer to suddenly open. Even if the pipe rams were immediately closed, uncontrolled flow could jeopardize rig and crew safety. It would be a matter of chance at this time whether a tool joint were opposite the closing pipe ram thus damaging it beyond subsequent sealing capability.

For the annular preventer designed without wellbore assist, increasingly higher hydraulic closing pressures are required to maintain the seal at higher and higher well pressures. Figure 6 shows results of shop tests of the wear on an element (stripping cycles to failure) relative to increasing wellbore pressure and the resulting increase in closing pressure. Note the drastic reduction in element life when well pressure is increased from 1,500 to 3,000 psi. While the results of the tests may vary somewhat among preventers, the size pipe used or the type of element installed, it is Exxon's position that the test is strongly indicative of the results that will be obtained at higher well pressures. In other words, the stripping wear life of an annular preventer is greatly reduced at increased wellbore pressures. Of equal significance is the need for the element to maintain its sealing capability when repeatedly moving the smaller diameter pipe body, then the larger diameter tool joint and then the smaller diameter pipe body again through the preventer. The element's ability to maintain a seal under this procedure is related to the amount of wear and pressure to which it is subjected. Although a provision is available for "slightly" reducing the amount of closing force on the element as the tool joint starts through, the opening and closing sequences of an annular preventer are not totally positive. This is due to the larger sealing and piston areas involved, the amount of probable wear, and the relatively large fluid operating volumes.

For these reasons, it is Exxon's normal policy not to attempt stripping operations using an annular preventer, regardless of its pressure rating, when well pressure exceeds 2,000 to 2,500 psi. Our practice is supported by the experience of Otis Engineering Corporation's worldwide stripping and snubbing operations. Otis' views on the subject are reflected in their letter of February 11, 1980, Figure 7. Supporting documentation can also be found in API Recommended Practices for Blowout Prevention Equipment Systems RP53 Page 14, Figure 8. Preventer system arrangements for 5,000, 10,000, and 15,000 psi pressure ratings may utilize annular preventers rated for 5,000 psi.

In summary, by design and operational usage, an annular preventer is intended to provide for a limited range of functions under low to moderate pressure, i.e., less than 5,000 psi. A regulatory requirement for a greater than 5,000 psi working pressure annular preventer distorts the purpose and operational usage of the annular preventer, potentially jeopardizing well control and safety under high pressures. Moreover, it is projected that several years would be required to design, shop test, and operationally validate the reliability of 10,000 psi annular preventers of the 16-3/4 inch or 18-5/8 inch sizes required in some drilling programs. This regulation could limit the availability of rigs for scheduled exploration drilling programs, require use of prototype equipment during well control operations, and result in no tangible advancement in technology or increased safety.

TLP/RAM/rms
211-A

TYPICAL BLOWOUT PREVENTER STACK

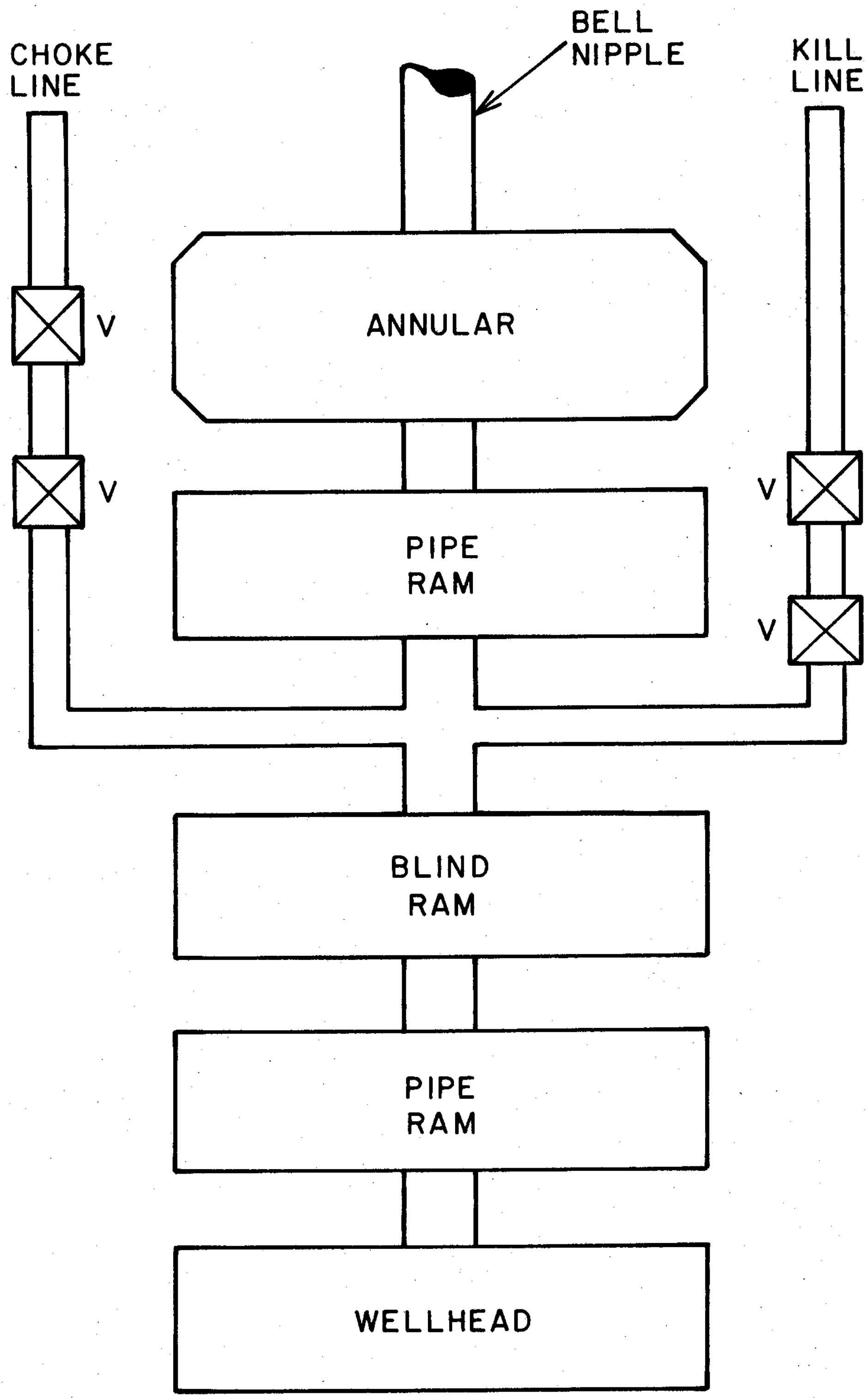

FIGURE I

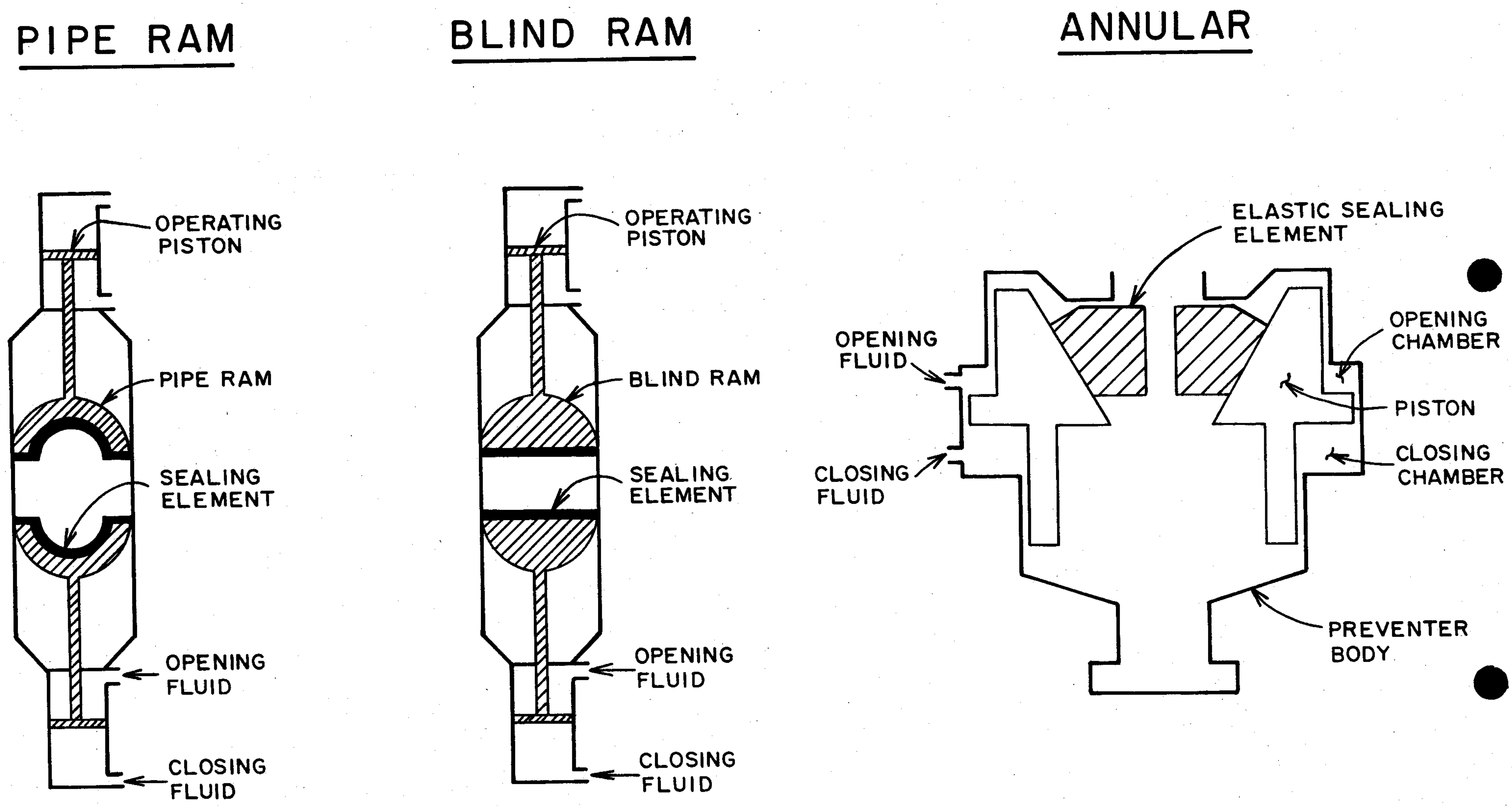
PIPE RAM
BLIND RAM
ANNULAR
OPERATING PISTON
PIPE RAM
SEALING ELEMENT
OPENING FLUID
CLOSING FLUID
OPERATING PISTON
BLIND RAM
SEALING ELEMENT
OPENING FLUID
CLOSING FLUID
ELASTIC SEALING ELEMENT
OPENING FLUID
CLOSING FLUID
OPENING CHAMBER
PISTON
CLOSING CHAMBER
PREVENTER BODY

FIGURE 2

LAND, PLATFORM & JACK-UP OPERATION

FULL BOP STACK ON COMPETENT CASING
CLOSING-IN PROCEDURE

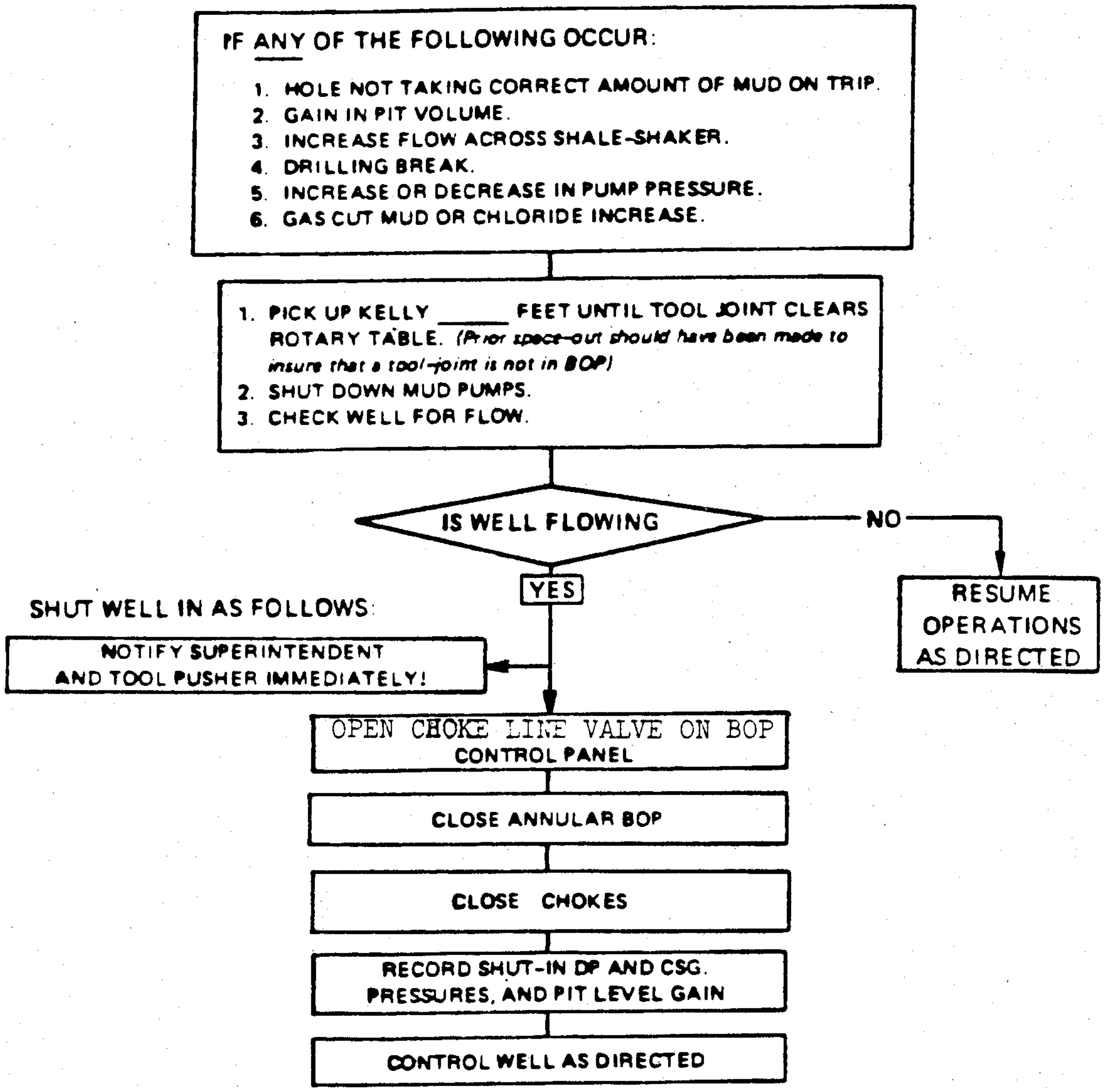

FIGURE 3

REQUIRED INFLUX
FOR INITIAL WELL SHUT-IN PRESSURE
TO EQUAL 5,000 PSI

Well TD-Ft	Drilling Mud Wt-ppg	Barrels of Gas Influx With A 2 ppg Kick	With A 4 ppg Kick
13,000	10.0	389	242
15,000	12.0	293	156
17,000	14.0	227	98

WELLBORE CONFIGURATION

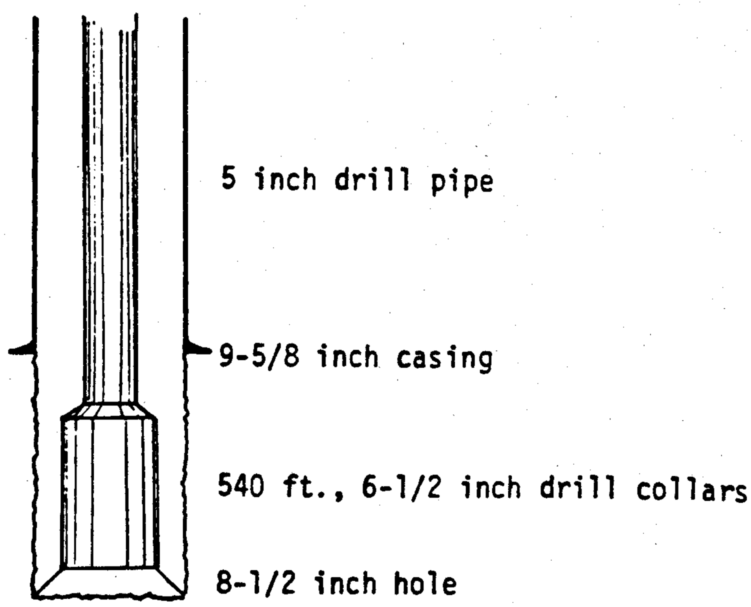

Figure 4

LENGTH OF PIPE REQUIRED TO STRIP THROUGH ANNULAR Vs WELLBORE PRESSURE

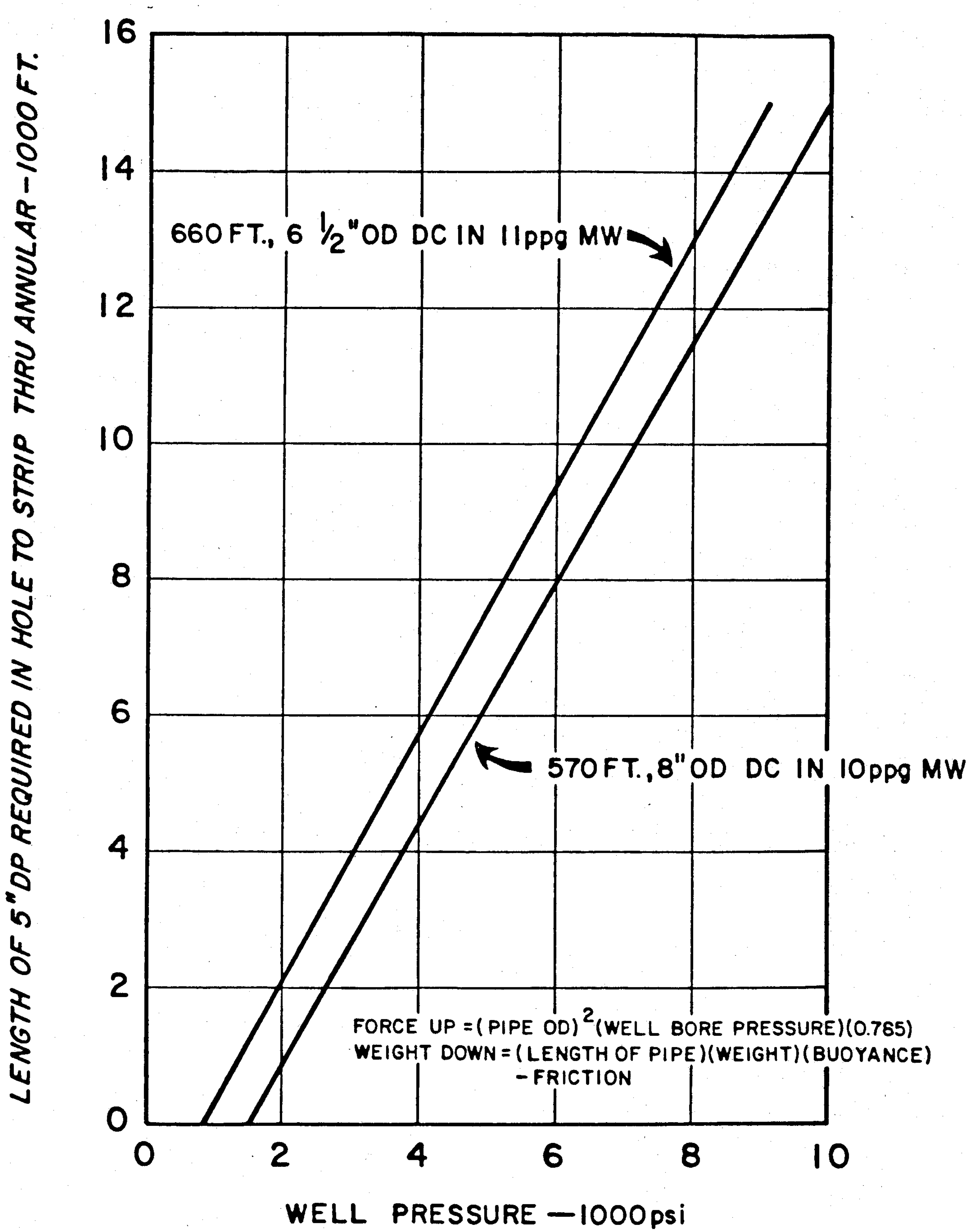

FIGURE 5

STRIPPING TEST RESULTS

18 3/4" AND 16 3/4"- 5000 PSI ANNULAR

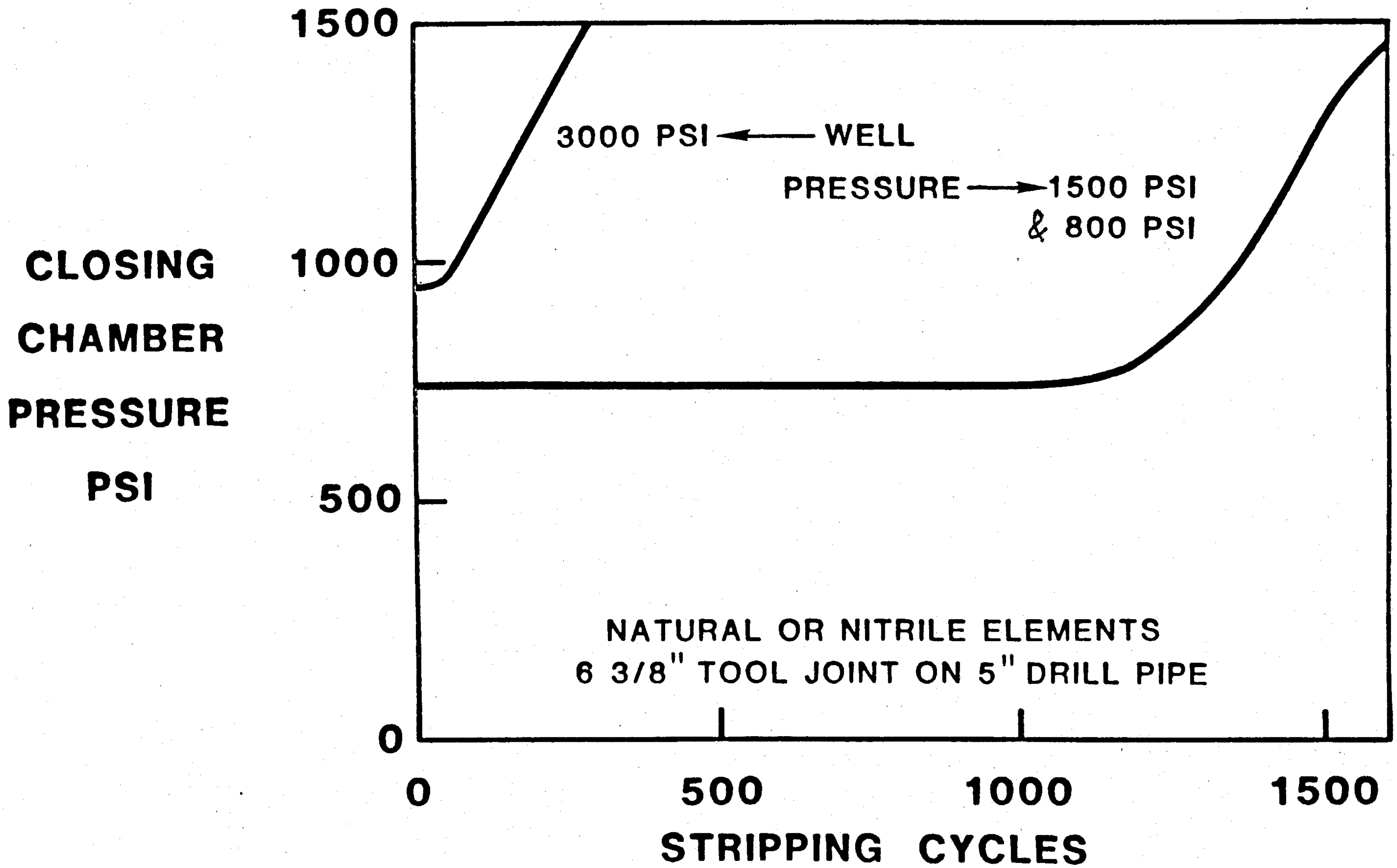

FIGURE 6

OTIS

P. O. BOX 34380 · DALLAS, TEXAS 75234
AREA CODE 214-242-8668

PHILLIP S SIZER, P.E.
SENIOR VICE PRESIDENT
TECHNICAL DIRECTOR

February 11, 1980

Mr. H. J. Flatt
Exxon Headquarters
Drilling Manager
Exxon Company, U.S.A.
P. O. Box 2180
Room 3005
Houston, TX 77001

Dear Sir:

With reference to your inquiry regarding the use of large bore annular preventers, Otis has had no experience stripping pipe using any annular type preventer above 10 3/4 I.D. We have had some experiences down through the years with emergency stripping of drill pipe, sizes 3 1/2 through 4 1/2, using the 7 1/16 I.D. annular preventer under 3,000 psi, but in each case we either had adequate pipe in the hole or our conventional snubbing equipment available for stripping purposes.

We regularly strip 1.315 O.D. through 2 7/8" O.D. using a pre-sized, molded stripper element similar to Hydril's RS Stripper, Composite Catalog, Page 3674. Most routine offshore workover is conducted with 1.315 O.D. pipe stripped through a molded stripper element sized to fit 4 1/16 bore equipment, 3,000 psi maximum.

We have used dual element stripping techniques but employ this method to lengthen element life as opposed to increasing working pressure ranges. Stripping with either the molded or annular type presents major problems when considering the change in areas as the joint upset moves through the seal area from two standpoints: 1) Sufficient pipe weight must be present to pull the joint through the seal area, and 2) Strict attention must be placed on the type of joint used. No square shoulders must be present and a very shallow angle must be used for the diameter transition.

I would suggest that smaller pipe diameters in relation to large bore annular preventers could present a problem unless the elastomeric material is adequately backed up by metal. One other concern is the tendency for the elastomeric materials to flow easily when the pressure differential approaches or exceeds the modulus of elasticity. This means that without near perfect metal backup, higher pressure sealing is not practical. We experience a certain amount of difficulty in the ram type preventer as well, and must be constantly aware of and accommodating to the metal backup configuration.

Figure 7

One point I should mention is, the industry also uses the term stripping to indicate the movement of pipe through ram type BOP's. I have assumed in your inquiry we are talking about annular type equipment as opposed to ram type equipment.

Our principal experience has been with ram type equipment, using pipe sizes up through 7" O.D. and pressure up through 18,000 psi. The large pipe has been stripped with ram type BOP's against 2,000 psi and the smallest pipe has been associated with ram type BOP's and 18,000 psi.

We would, if required to rig up on an existing stack, test all BOP's including the annular to rated working pressure but would not attempt to strip more than 5,000 psi using a 7-1/16 I.D. annular preventer. We believe increases in bore will reduce this maximum drastically as 18 3/4 I.D. is reached.

I hope the foregoing is useful in helping you arrive at a decision but if additional information is necessary, please contact me.

Yours very truly,

OTIS ENGINEERING CORPORATION

Phillip S. Sizer

Phillip S. Sizer

PSS:mc

cc: Mr. Homer Davis

Figure 8

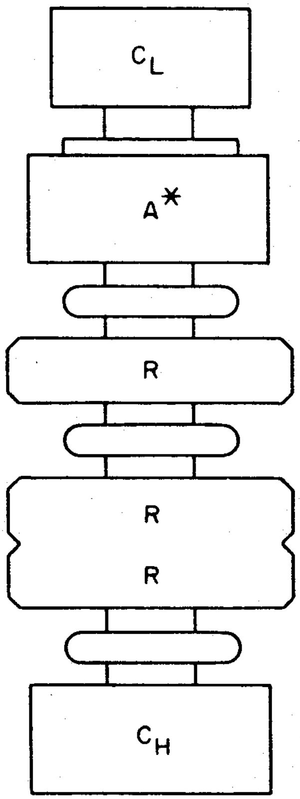

FIG. 2.D.4

ARRANGEMENT $C_HR_dRA^*C_L$
Triple Ram Type Preventers, R_t, Optional.

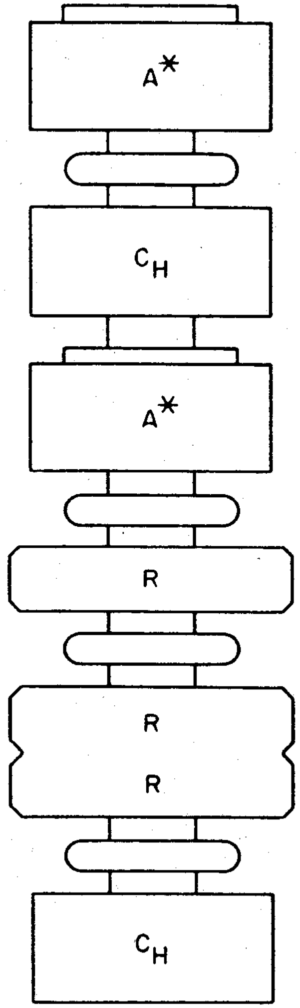

FIG. 2.D.5

ARRANGEMENT $C_HR_dRA^*C_HA^*$

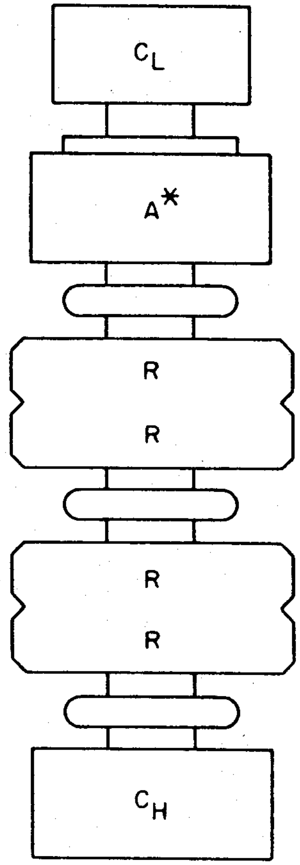

FIG. 2.D.6

ARRANGEMENT
$C_HR_dR_dA^*C_L$

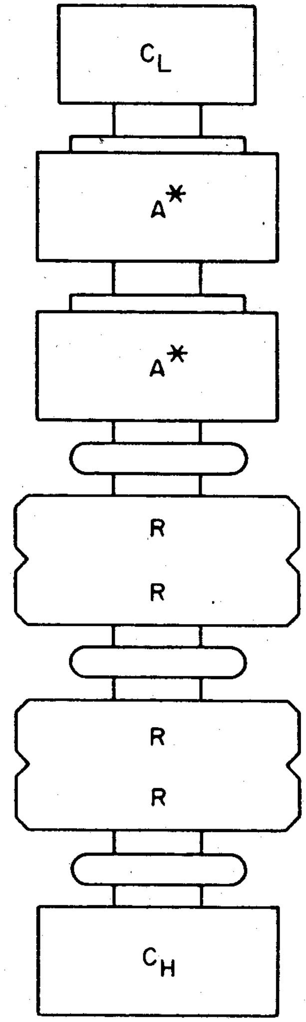

FIG. 2.D.7

ARRANGEMENT
$C_HR_dR_dA^*A^*C_L$

*Annular preventer, A, may have 5M working pressure rating.

TYPICAL BLOWOUT PREVENTER ARRANGEMENTS FOR 5M, 10M, AND 15M RATED WORKING PRESSURE SERVICE — SUBSEA INSTALLATION